Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Emission Rate Input									
		Stack Velocity	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
NOx Control	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.19
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.19
LNC3+ with Tuning	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1	0.17
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5	0.17
SNCR	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	49%	902.6	0.14
	1 & 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	50%	1806.3	0.14
SNCR with LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2	0.12
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4	0.12

Year 2000 Modeling Results

Description			Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units	Average Improv-ement	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
	1& 2	59%	17	0.217	0.860	16	0.235	0.959	10	0.186	0.596	28	0.376	0.954
LNC3+ with Tuning	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
	1& 2	56%	18	0.251	0.970	18	0.245	0.909	11	0.175	0.627	29	0.426	0.983
SNCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
	1 & 2	86%	5	0.080	0.310	4	0.083	0.290	2	0.056	0.209	3	0.140	0.326
SNCR with LNC3+	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
	1& 2	58%	17	0.235	0.918	17	0.236	0.860	10	0.163	0.605	26	0.409	0.924

Year 2001 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
LNC3+	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
	1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
LNC3+ with Tuning	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
	1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
SNCR	1	62%	7	0.101	0.453	7	0.133	0.467	4	0.074	0.433	16	0.192	0.486
	1 & 2	60%	19	0.202	0.884	21	0.267	0.917	12	0.147	0.847	33	0.192	0.486
SNCR with LNC3+	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
	1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417

Year 2002 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
	1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
LNC3+ with Tuning	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
	1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
SNCR	1	63%	20	0.193	1.088	14	0.138	0.850	11	0.123	0.692	12	0.148	0.722
	1 & 2	60%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
SNCR with LNC3+	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
	1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement
Pre-BART Protocol	1	1.033	NA	NA	1.151	NA	NA	2.047	NA	NA	1.410	NA	NA
	1& 2	1.890	NA	NA	2.095	NA	NA	3.565	NA	NA	2.517	NA	NA
LNC3+	1	0.438	0.594	0.594	0.515	0.636	0.636	0.947	1.100	1.100	0.634	0.777	0.777
	1& 2	0.842	1.048	1.048	0.885	1.211	1.211	1.806	1.760	1.760	1.178	1.339	1.339
LNC3+ with Tuning	1	0.413	0.620	0.025	0.484	0.667	0.031	0.897	1.151	0.051	0.598	0.812	0.036
	1& 2	0.872	1.018	-0.030	0.833	1.263	0.052	1.713	1.852	0.093	1.139	1.378	0.038
SNCR	1	0.141	0.892	0.272	0.460	0.691	0.024	0.838	1.209	0.059	0.480	0.931	0.118
	1 & 2	0.284	1.606	0.589	0.784	1.312	0.049	1.599	1.967	0.115	0.889	1.628	0.251
SNCR with LNC3+	1	0.362	0.670	-0.221	0.424	0.727	0.036	0.800	1.248	0.038	0.529	0.882	-0.049
	1& 2	0.827	1.063	-0.543	0.731	1.365	0.053	1.529	2.036	0.070	1.029	1.488	-0.140

Appendix E

Low-Baseline NOx SNCR Demonstration (EPRI Study)

This appendix contains confidential business information and is being submitted under separate seal.
Copyrighted material is not currently available for public release.

Appendix F

URS SNCR Evaluation Supplement

URS

March 30, 2012

Debra Nelson
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369

RE: URS Response to EPA FIP Exchange

Dear Debra:

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide:

- A site-specific rough order of magnitude estimate with a stated accuracy of ±30% for the 2011 capital cost required for installation of SNCR onto the Coal Creek units
- Site-specific operating and maintenance costs for SNCR operation at Coal Creek
- The level of NOx reduction expected when using SNCR on these units.

Cost Estimating Methodology - The basis for the cost estimates was stated to be the EPRI IECCOST model, which URS previously developed for the Electric Power Research Institute. This model provides site-specific cost estimates for all types of emissions control system installations, including individual systems that are designed to remove SO_2, NOx, Hg, and particulate matter. It also evaluates costs for multi-pollutant control systems, producing conceptual cost estimates that are site-specific based on the plant location, current operating characteristics, fuels burned, etc.

EPRI IECCOST Model development has continued for more than ten years; during that period URS has installed all of the commercial systems at utility installations, and become intimately familiar with all emissions control technologies. Consequently URS is very familiar with the relationship between the vendor island costs and the Total Capital Requirement for an emissions control retrofit. This extensive project experience also identified the performance capabilities and emission rate guarantees for the various technologies through review of bid documents and budgetary quote submittals under real world conditions.

The model is updated and escalated continuously as new projects are completed, calibrating the cost estimating results against actual project costs and performance. The economic model used for these calculations is IECCOST Version 3.1 that will be published by EPRI later in 2012.

URS Capabilities and Qualifications - URS is an engineering and construction company that has provided emissions control technology assessments, economic analyses, balance of plant designs, construction, construction management and startup assistance to utility and other industrial clients since the 1970's. During this period, URS participated in more than 30 SNCR projects at multiple sites using systems supplied by multiple vendors.

Total Capital Requirement Cost Estimates - URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls interface,

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interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

Retrofit Factor - A site visit was made to the Coal Creek plant by one of the URS air quality control engineering staff. Based on his assessment of the site and the location for installation of the SNCR equipment, the retrofit difficulty for this plant was established to be moderately difficult due the constraints provided by existing equipment at the plant. Based on previous industry assessments of the cost impacts of retrofit difficulty, a retrofit factor of 1.6 was established for this moderately difficult SNCR installation. Previous industry surveys by Radian and Kellogg (EPA-450/3-74-015 – "Factors Affecting Ability to Retrofit FGD Systems" & EPA R2-72-100 – "Applicability of SO_2-Control Processes to Power Plants" and the EPA/600/S7-90/008 – "Verification of Simplified Procedure for Site-Specific SO_2 and NOx Control Cost Estimates") attempted to quantify the retrofit cost impacts compared to new equipment installations. These surveys established retrofit factors based on retrofit difficulty that are multiplied times the new plant installed cost estimates to determine the retrofit installed cost. The site assessment by the URS staff resulted in the moderately difficult retrofit assessment, which was translated in the capital cost estimate as a 60% adder to the new equipment installation cost to account for decreasing productivity due to movement of parts and materials around existing equipment and structures, limited access to construction sites due to overhead, underground and side obstructions by existing equipment, crane access, etc.

SNCR Expected Performance – SNCR system performance is directly impacted by the flue gas temperature at the point of urea/ammonia injection, and by the current concentration of NOx in the outlet flue gas. Injection outside the correct temperature window results in significant reductions in reduction efficiency. The lower the current NOx concentration in the outlet flue gas, the lower the reduction efficiency that can be achieved (reduced driving force for the NOx reduction reactions). The performance claims in published articles are typically short term, optimized test results, and are typically inflated compared to the performance guarantees that are actually offered for actual installations. Given the relatively low NOx concentrations in the Coal Creek flue gas, the reduction capabilities of SNCR were set at values in the 20-30% range based on data from other recent projects. The urea feed rate used in the calculation of operating costs

For comparison, recent FuelTech papers (one of the major SNCR vendors) stated that larger utility boilers (such as exist at Coal Creek at 605MW) have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 20 – 30% are common for units that start with NOx emission rates of 0.15-0.25 lbs NOx/MMBtu. Urea injection rates to obtain these reduction efficiencies varied from site to site, but fell in the range of 1.1-1.5 normalized stoichiometric ratio while maintaining acceptable ammonia slip rates. All-in costs for these systems were stated to be in the range of $10-20/kW. The injection rates assumed for this URS analysis of SNCR for Coal Creek used NSR injection rates that varied from 1.3-1.5 over the range of control evaluated of 20-30% NOx reduction. All of these performance values and estimated capital costs fall in the ranges stated in the supplier papers.

URS

If you have any additional questions, please contact me.

Sincerely,

Robert J. Keeth
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Appendix G

Golder Fly Ash Evaluation Supplement

April 2, 2012 Project No. 113-82161

Diane Stockdill
Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

RE: SNCR IMPACT TO FLY ASH MARKETABILITY AND MANAGEMENT COSTS

Dear Diane:

1.0 BACKGROUND

Golder Associates Inc. (Golder) submitted a report to Great River Energy (GRE) on November 15, 2011, providing a third party review of Headwater's ammonia slip mitigation (ASM) technology. Additionally, the review included a detailed engineering estimate of potential disposal costs associated with fly ash impacted by ammonia slip from selective non-catalytic reduction (SNCR) emission controls at GRE's Coal Creek Station (CCS).

This report was included as part of GRE's submittal of November 21, 2011 to the U.S. EPA Region 8 (EPA), with comments responding to the Proposed Rule for the Approval and Promulgation of Implementation Plans: North Dakota Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA-R08-OAR-2010-0406).

The EPA provided a prepublication version of the "final rule" to GRE on March 2, 2012, which included EPA's response to various comments including those in GRE's November 21, 2011 submittal:

- Section V: Issues Raised by Commenters and EPA's Responses;
- Part E: Comments on BART Determination;
- Subpart 2: CCS Units 1 and 2;
- Item d: CCS Coal Ash had several comments; and
- EPA responses addressing the potential for SNCR to impact fly ash sales and the cost of this impact.

Below are Golder's responses to the EPA's comments on our November 15, 2011 report concerning the potential impact of SNCR controls to fly ash marketability at CCS and the potential cost impact if fly ash requires ASM technology and is less marketable and therefore, placed in greater quantities into disposal facilities.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles, and the acceptable (allowable) ammonia levels in fly ash by the fly ash end users.

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2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to "restricted use" of fly ash and ammonia slip levels above 4 ppm may lead to "unmarketable" fly ash for use in ready mix.

2.2 Allowable Ammonia Present In Fly Ash

The amount of "allowable" ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Headwaters Resources, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the "...industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable." Headwaters indicated (January 11, 2010) that they "...quit shipping anything over 100 ppm..." in reference to the Eastlake facility, which has had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found "...when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable." Additional references have generally found that approximately 100 ppm is the maximum "acceptable" ammonia level in fly ash (Bittner et al. 2001, Giampi 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces, but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA's permissible exposure limit (PEL) is 50 ppm. A "comfortable" threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water - to - Cement\ ratio)}{(Fly\ Ash\ Content)}$$

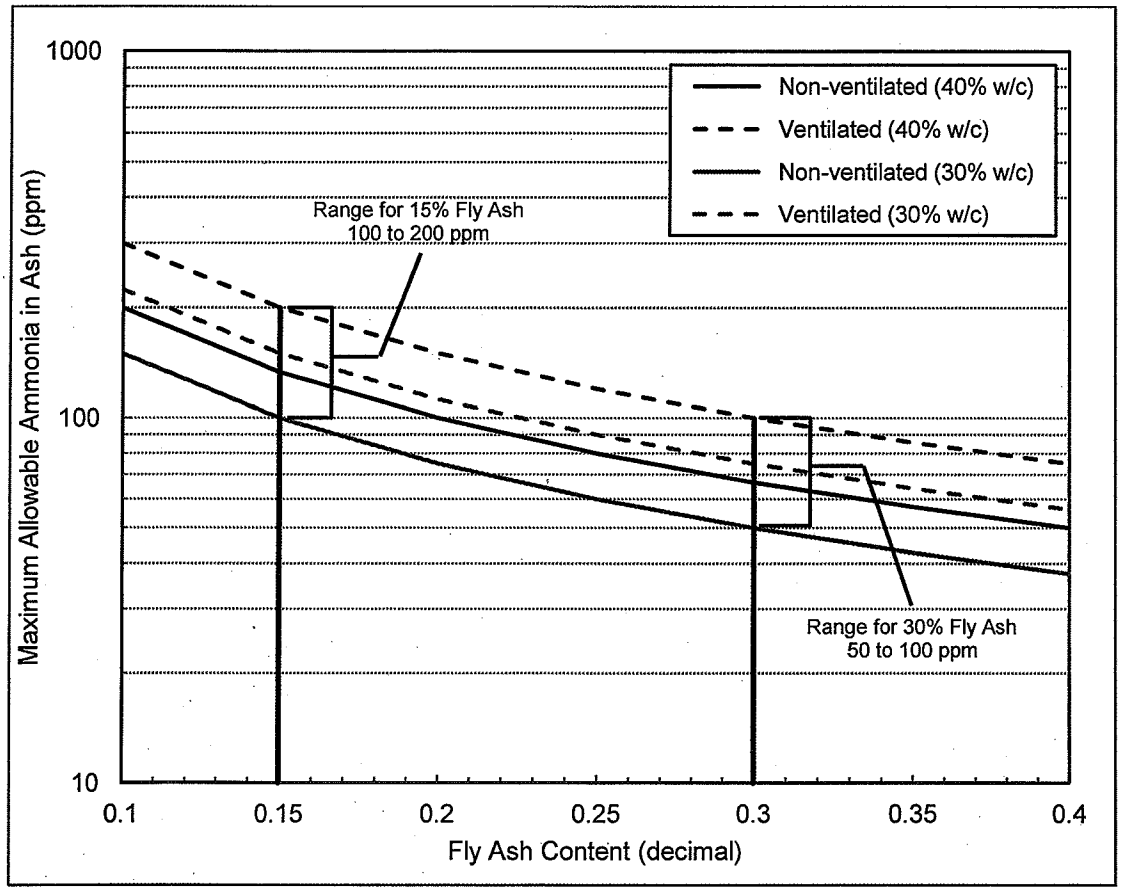
The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in the following table and the figure below.

Condition	**Ammonia in Air***	**Water/Cement Ratio**	**Allowable Ammonia Content in Fly Ash (15% fly ash mixture)**	**Allowable Ammonia Content in Fly Ash (30% fly ash mixture)**
	ppm	**-**	**ppm**	**ppm**
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				



2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. Because the ash marketer and ready mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications. This limit is also supported by the anecdotal comments from both Headwaters and Lafarge.

Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering costs evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 SNCR COST IMPACT TO FLY ASH MANAGEMENT

Golder previously provided a detailed engineering cost estimate for the potential impact to fly ash management as a result of SNCR emissions controls at CCS. Based on the EPA responses, supporting information and clarifications are provided below.

3.1 Fly Ash Disposal Facility Design Basis

The previous evaluation indicated that each cost estimate was prepared assuming that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices. This may have been taken as a speculative/highly conservative estimate based on impending coal combustion residue (CCR) regulations being developed by the EPA (see EPA response to comment on page 111 of rule prepublication).

In actuality, the assumed design is based on current North Dakota Department of Health (NDDH) regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html), which are in-line with RCRA Subtitle D practices. In the early 1990s the NDDH revised its Solid Waste Management and Land Protection rules adopting environmentally sound controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring.

3.2 Fly Ash Disposal Unit Cost Estimate

Disposal costs of $11 to $18 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care. In the EPA's responses (page 110), they indicated "we find a disposal cost of $5/ton is reasonable in the improbable event that some ash would need to be disposed."

The cost estimate of $5/ton deemed reasonable by the EPA is not supported by an engineering cost estimate, is not supported by industry information, and is not supported by recent work published by the EPA.

In 2010, the EPA estimated baseline (i.e. current) CCP disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2/ton to $80/ton with an average of $59/ton. In discussion of these results, the report indicates that $2/ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80/ton is reflective of off-site commercial disposal in landfills. Fly ash disposal facilities at CCS are clay- or composite-lined, engineered impoundments and landfills located at varying distances from the plant. North Dakota has comprehensive regulatory requirements in place for ash disposal facilities.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> "As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time." (ACAA, http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $11 to $18 per ton appears well within the EPA's cost estimate and industry practice.

3.3 Lost Fly Ash Sales Revenue

Part of the cost impact to fly ash management is the loss of fly ash sales revenue currently being generated. Based on information from GRE, the 2010 average fly ash sales price per ton was $41.00 with 30% of the sales price going to GRE ($12.30/ton) as revenue and 70% of the sales price going to the fly ash marketer Headwaters ($28.70/ton).

EPA commented that GRE should use $5/ton rather than the updated value of $12.30/ton, and suggested that the lost revenue price included lost revenue to other parties. Based on follow-up discussions with GRE, it was confirmed that the $41/ton is the 2010 average FOB Coal Creek Station sales price and the $12.30/ton portion attributed to GRE does not include lost revenue to other parties. Based on this confirmation, the $12.30/ton rather than the $5/ton is more appropriate for the conditions at Coal Creek Station.

3.4 Cost Impact Conclusions

The fly ash disposal cost estimate is based on an engineering design reflective of the practice in North Dakota, and Golder's engineering estimate of $11 to $18 per ton for fly ash disposal appears to be well within the EPA's cost estimate and consistent with industry practice. Further, the lost fly ash sales revenue of $12.30/ton reported in the cost impact evaluation is reflective of current conditions at CCS.

The disposal and lost revenue cost estimates are valid, and based on the uncertainty with respect to ammonia levels in fly ash, the previous evaluation with respect to fly ash management cost is reasonable.

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Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;
- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;
- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and
- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. <u>EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination</u>

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

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[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.

[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.

[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id.* In the final FIP, EPA asserts that SNCR at CCS would not contaminate <u>any</u> fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

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[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between $11 and $18 per ton. Golder also demonstrates that EPA's estimate of $5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of $2 to $80 per ton, with an average cost of $59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is $12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash

would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

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Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
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CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.