

DAKOTA GASIFICATION COMPANY

A BASIN ELECTRIC SUBSIDIARY

GREAT PLAINS SYNFUELS PLANT
420 COUNTY ROAD 26
BEULAH, NORTH DAKOTA 58523-9400
PHONE 701/873-2100
FAX 701/873-6404



June 19, 2009

JUN 22 2009

Mr. Lee Gribovicz, Project Manager
Western Regional Air Partnership
1600 Broadway, Suite 1700
Denver, Colorado 80202

Dear Mr. Gribovicz:

Thank you for the opportunity to provide comments on the document created for Western Regional Air Partnership (WRAP) entitled "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota." The Four-Factor Analyses, hereafter referred to as the WRAP document, references the Riley boilers at the Great Plains Synfuels Plant (GPSP) and makes a case for why Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) should be considered in setting reasonable progress goals to reduce NO_x emissions and improve regional haze. Dakota Gasification Company (DGC) supports the document presumption that the facility already meets the requirements for sulfur reduction technologies.

DGC is concerned about the high capital and operating costs associated with the NO_x removal technologies outlined in the WRAP document. Additionally, DGC is concerned that the capital cost and operating cost outlined in this report may be somewhat underestimated because it has not accounted for the unique operation at the GPSP. Finally, DGC is concerned that the estimated control efficiency may be overstated relative to the capital expended.

Theoretically, SCR and SNCR appear to be good technologies for controlling NO_x from the Riley boilers; however, neither has been proven to work with DGC's unique boiler fuels. The Riley boilers are fired with a variety of liquid *and* gaseous lignite-derived fuels. The capital and operating cost referenced in the WRAP document is based on either liquid-fired *or* gas-fired boilers. The reference does not address the cost implications for the unique combination of fuels fired at the GPSP.

DGC is not certain that SCR is technically feasible with the existing process at the GPSP. Furthermore, DGC has information that the cost may be significantly higher than reported in the WRAP document. In 1996, DGC installed a Flue Gas Desulfurization Unit as Best Achievable Control Technology (BACT) for sulfur dioxide. During the evaluation process leading up to the BACT installation, DGC evaluated a proposal for SCR on the Riley boilers. The proposal would have required modifications to the heat recovery section of the Riley boilers to increase the temperature of the flue gas entering the SCR. Presumably, the current operating temperature is not sufficient for effective SCR operation.

The required modifications would have reduced the capability of the boilers to make enough steam to operate the facility at full production. Therefore, the cost estimates in the WRAP



Equal
Employment
Opportunity
Employer

document for installing SCR at DGC are too low because they do not account for the capital costs associated with modifying the Riley boilers and the production lost during that effort. Additionally, the operating cost estimates do not account for the continuing plant production losses directly related to the reduction in steam capacity from the Riley boilers.

Regarding SNCR, DGC has information that suggests it may not be technically feasible at DGC's GPSP. In 1997, DGC experimented with SNCR as a NO_x control on the Riley boilers. The injection of ammonia during this testing resulted in the rapid accumulation of ammonium sulfate particulate deposits in the heat recovery section of the boiler. The uniqueness of the flue gas (high SO₂ and CO₂) is believed to have contributed to the formation of ammonium sulfate in the boilers. This highly undesirable side effect combined with a much lower than predicted NO_x reduction prompted DGC to immediately discontinue testing. Further testing was not performed due to the likelihood of interfering with the long-term reliability and performance of the Riley boilers.

In addition to the typical cost of the control technologies themselves, other costs of installing SCR or SNCR will include engineering challenges of finding a place to install equipment in an area with limited space available. DGC has the concern that a retrofit installation for SNCR or SCR would drive the costs higher than the costs noted in the high level overview provided in the WRAP document. The reference for the WRAP document does not clearly indicate if a congested work site comparable to that at DGC has been considered in the capital cost estimate.

The WRAP document based the capital cost, operating cost, and overall effectiveness of the control technology by applying control technology only to the Riley boilers and not the two liquid-fired superheaters. This is an understandable approach by the author because the superheaters are equivalent to only 10% of the Riley boiler heat load. However, DGC's sampling indicates that the superheaters could contribute over 20% of the total NO_x produced. In order to achieve the maximum NO_x control referenced in the WRAP document, DGC would have to expend additional costs for controls on the superheaters.

Any new technology that is considered for NO_x controls will require an evaluation. Depending on the technology chosen, time and resources may need to be allotted to construct and operate a pilot plant to prove a chosen technology will work in this application.

Before requiring expenditure of significant amounts of capital to install new emission controls, consideration should be given to the overall impact of any required emission reduction. The NO_x emissions from the GPSP are a small part of the state inventory. Therefore, it does not seem cost-effective that DGC should bear the expense of adding costly controls. Good emission control strategies should target regional sources that are more cost-effective and feasible.

In addition to the four-factor analysis, a fifth factor needs to be part of this analysis. Any determination for the application of additional controls to reduce primary pollutants must further consider the degree of visibility improvement on a deciview (dv) and cost per dv (\$/dv) basis that would be incurred by the implementation of any controls. This factor is of great importance and should be a major consideration.

Mr. Lee Gribovicz, Project Manager

June 19, 2009

Page 3

If an emission reduction is required for a facility, DGC suggests that the agency issuing the requirement explain what reductions are needed and how those reductions are considered to be possible based on technology available. The agency should also allow facilities the flexibility to identify new and innovative ways to achieve those reductions that may not have been initially considered in the WRAP document.

DGC appreciates your consideration of our comments. Given the reasons detailed in this letter, DGC believes the control technologies for SCR and SNCR on the GPSP Riley boilers should not be considered within the first State Implementation Plan (SIP) on Regional Haze.

Sincerely,



David W. Peightal, P.E.
Environmental Manager

dwp/paw

c: Terry O'Clair, NDDH
Tom Bachman, NDDH
9850-DWP-09-008