BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
OF THE STATE OF WYOMING

IN THE MATTER OF:	)	
BASIN ELECTRIC POWER COOPERATIVE	)	Docket No. 07-2801
DRY FORK STATION,	)	Presiding Officer, F. David Searle
AIR PERMIT CT–4631	)	
____	)	

REBUTTAL EXPERT REPORT OF RANAJIT SAHU

1. My experience and qualifications are provided in my Expert Report dated May 8, 2008.

2. This report contains my rebuttal to the Expert Report and Analysis produced by Mr. Kenneth J. Snell of Sargent and Lundy LLC (S&L). I will refer to this report as the Snell Report hereafter.

I. Subcritical vs. Supercritical Boiler Technology

3. With respect to the choice of technology (i.e., subcritical versus supercritical), the Snell Report ignores the examples of several smaller (i.e., comparable to the size of the Dry Fork plant) units that are supercritical and which have higher efficiencies that what is expected from the Dry Fork Unit.[1] Vendor information in the record does not provide support for Mr. Snell's position that vendors could not supply units in the size range of 400 MW with super-critical turbines. Smaller sized supercritical units are available and operational (supercritical is at 221.2 bar). I have excerpted below, a table showing at least three supercritical units ranging from 390-411 MW gross (smaller than the Dry Fork unit, which is 422 MW gross). The last column shows that their plant efficiencies are greater than 47% on a net LHV basis.[2]

Country	Power Plant	Unit Rating MWe net (gross)	Steam Press (bar)	Main Steam Temp (°C)	Reheat RH1 Steam Temp (°C)	Reheat RH2 Steam Temp (°C)	Efficiency (% net LHV)
Denmark	Avedoreværket 2	390	300	580	600	———	48.3
Denmark	Nordjylland 3	411	285	580	580	580	47
Denmark	Skærbæk 3	411	290	582	580	580	49

[1] Snell Report, p. 15. The table shows that the expected plant efficiency for the Dry Fork Unit is expected to be 36.14%

[2] Advanced Power Plant Using High Efficiency Boiler/Turbine, DTI Best Practice Brochure, January 2006 (attached as Exhibit 1).

4. According to Mr. Snell, S&L considered Dry Fork specific design criteria to determine that the efficiency gains normally attributable to a supercritical boiler would not apply to the Dry Fork Station.[3] However, neither Mr. Snell nor the S&L June 11th, 2007 Technical Memo provide an adequate explanation for why the site-specific conditions at the Dry Fork Station would prevent attainment of efficiencies demonstrated at other existing supercritical units in the 400 MW size range. The Snell Report relies largely on potential efficiency losses associated with the HP turbine for smaller (i.e., less than 500 MW) units.[4] However, the actual difference in these losses, for units that are 500 MW versus those that are the size of the Dry Fork unit, are not discussed. No vendor (i.e., turbine manufacturer) data are presented. Mr. Snell does not provide calculations or other support for his assertion of a 2.3% theoretical gross turbine heat rate efficiency gain with a supercritical cycle. Mr. Snell also provides no data or calculations to support his conclusion that the actual improvement in gross turbine heat rate with a surpercticial cycle on the Dry Fork boiler would be in the range of 0.75% to 1.3%. Without support for these figures, Mr. Snell has failed to demonstrate that the supercritical technology in place at other similarly sized plants would not result in increased efficiency at the Dry Fork Station.

5. Mr. Snell's analysis of costs ignores costs associated with carbon emissions. Supercritical units will emit less carbon dioxide due to their higher efficiency. The costs associated with carbon emissions for the life of the plant, assuming the range of carbon costs likely as a result of expected regulation, should be included in any cost analysis. Utility planning today invariably includes the costs of expected future carbon emissions. Even investors are including such costs in plant economic fesasibility analyses.[5] If costs associated with carbon capture are included, then the higher costs associated with subcritical units becomes apparent. I have shown below, an excerpt of a recent Table prepared by the National Association of Regulatory Utility Commissioners (NARUC),[6] showing just such a comparison. While the actual costs may be different today than when the underlying report was prepared, there is no reason to believe that the relative cost differential is any different today between supercritical and subcritical plants. The costs below are for a 500 MW reference plant.

Table 1: Comparison of Fossil–Fue

	SUBCRITICAL PULVERIZED COAL		SUPERCRITICAL	
	Without CO_2 capture	With CO_2 Capture	Without CO_2 capture	With CO_2 Capture
Total Plant Cost ($/KW, MIT)	$1,280	$2,230	$1,330	$2,140

[3] Snell Report, pg. 14.
[4] Snell Report, pg. 14-16.
[5] See, for example, http://blogs.wsj.com/environmentalcapital/2008/02/13/bank-of-america-puts-a-price-on-carbon/. In this article, Bank of America says it has decided to start factoring a cost of carbon-dioxide emissions into its decisions about whether to underwrite debt for new coal-fired plants. Specifically, the bank says it anticipates a federal cap that would require a utility to pay between $20 and $40 for every ton of CO2 its power plants emit. Today in Europe, which already has imposed caps, a permit to emit a ton of CO2 is trading at about $29.
[6] Clean Coal Generation Technologies for New Plants, NARUC, March 2008 (attached as Exhibit 2).

II. PM2.5

6. WYDEQ-WDAQ did not conduct a PM2.5 BACT analysis. Instead it relied on its PM10 analysis to meet PM2.5 BACT requirements. WYDEQ-WDAQ should have considered the following in the 5 step BACT review process for PM2.5:

Step 1: Identify all control technologies. Along with an electrostatic precipitator (ESP) and a baghouse, Dry Fork should have also identified an advanced hybrid particulate collector, a more efficient baghouse, a wet ESP (including membrane wet ESPs[7]), and a wet FGD. It should have also discussed technologies such as the Indigo agglomerator that are now being used to enhance PM2.5 collection efficiency.[8] Because the control efficiencies that can be obtained by these technologies depend on their design and operating details, the specific designs of these technologies that provide the highest control efficiencies should have been considered. For example, the types of bags to be used in a baghouse determine the level of control achievable. EPA's Environmental Technology Verification (ETV) Program has certified extremely low levels of PM2.5 emissions from particular bags – such as fabric filter L3650 by W.L. Gore and Associates, Inc.[9] These bags reduced inlet dust concentrations of approximately 8 grains per dry standard cubic feet (gr/dscf) down to less than 0.00007 gr/dscf for total filterable PM as well as filterable PM2.5, which equates to an emissions reduction of over 99.999%. Similarly, bags designed for PM2.5 or sub-micron removal, such as ePTFE membranes, should have been considered as well but were not.[10] These and other types of specific design elements should have been considered in this step.

Step 2: Eliminate technically infeasible control technologies. All of these technologies are technically feasible, including the advanced hybrid particulate collector. A full scale advanced hybrid particulate collector was installed and operated at the Otter Tail Big Stone I for more than 3 years. While I understand that there were operational issues associated with the long term operations of this technology, very high levels of PM removal were obtained by this technology.[11]

Step 3: Rank remaining control technologies. As noted above, depending on the design of the control technology such as baghouses, ESPs, etc., the control efficiency can vary. Both ESPs and fabric filters are highly efficient particulate removal devices with design efficiencies in excess of 99.5%. In fact the range of efficiencies obtainable from ESPs and baghouses is 99% to over 99.9999%, for particles in the range 0.01 microns to over 100 microns.[12]

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[7] Caine, J., et. al., "Membrane WESP – A Lower Cost Technology to Reduce PM2.5, SO3, and Hg+2 Emissions," (attached as Exhibit 3).
[8] Crynack, R., et al., "Reducing Fine Particle Emissions from US Coals Using the Indigo Particle Agglomerator" Paper No. 04-A-42-AWMA (attached as Exhibit 4).
[9] See ETV Joint Verification Statement, "Control of PM2.5 Emissions by Baghouse Filtration Products," L3650, (attached as Exhibit 5).
[10] Midwesco Filter Resources, Inc. Technical Data Sheet, "Why Membrane? Exploring the Benefits of Surface Filtration" (attached as Exhibit 6).
[11] Rinschler, C., Advanced Hybrid Technology, World Cement, Feb., 2002 (attached as Exhibit 7).
[12] http://www.iea-coal.org.uk/site/ieacoal/clean-coal-technologies-pages/fabric-filters-baghouses.

Step 3 should also have specifically considered condensable particulate matter since technologies such as wet ESP or high efficiency wet FGD with mist eliminators can achieve high levels of condensable PM2.5 removal, depending on design.

Step 4: After Step 3 is completed, the most effective (i.e., highest control efficiency designs) are usually evaluated in a case by case analysis, considering the typical BACT collateral impacts (energy, environmental, and economic impacts). It is my opinion that a baghouse with a minimum efficiency of over 99.9% (for filterable PM2.5) in combination with a high efficiency wet scrubber (99% SO2 removal, with mist elimination), followed by a wet ESP (which can be designed to achieve over 90% control for condensable PM2.5) should have been evaluated in this step.

Step 5: Select BACT. Based on the results of Step 4, separate limits for filterable and total (including condensable) PM2.5 should have been selected as BACT.

III. BACT Limits

A. Averaging Times

7. Mr. Snell argues that my criticism relating to the lack of shorter term (i.e., less than 12 months) averaging time BACT limits (in lb/MMBtu) is unfounded since the proposed unit will be base-loaded and therefore "even in the short-term, the Dry Fork boiler will have to achieve controlled NOx and SO2 emission rates very close to the 12-month lb/MMBtu permit limits in order to ensure compliance with the 30-day lb/hr permit limit."[13] It appears that Mr. Snell is conceding that the 30-day emission rates will have to be "very close" to the 12 month permit limit. If this is the case, Dry Fork must accept the same annual BACT limits on a 30-day basis. It is my opinion that, for, a base-loaded unit (as the Dry Fork unit is), there should be no realistic difference between 12-month and 30-day operating (and therefore emissions) variability. Therefore, Mr. Snell's analysis actually provides additional support for my assertion that 30-day BACT limits, equally to the annual limits, in lb/MMBtu, are and should be achievable. Having such BACT limits, in lb/MMBtu, will mean that short term emissions will be less than they would be under the current mass limit of 190 lb/hr.

B. NOx

8. Mr. Snell notes that, for NOx, "[A]n emission rate of 0.045 lb/MMBtu is very close to the design limit of the SCR control system."[14] However, SCR emission rates are a function of SCR design parameters including the characteristics of the inlet gas stream, the type and amount of catalyst in the SCR, and other factors. Therefore, in order to properly assess this "design limit" for Dry Fork, one would need vendor information on actual design parameters. This information is not provided.

[13] Snell Report, p. 34.
[14] Snell Report, p. 35.

9. The Snell Report discusses the rationale for "a reasonable margin between the design target and permit limits."[15] For NOx, S&L chose three "representative" units to evaluate SCR cost effectiveness. However, except for the fact that these units are pulverized, sub-critical units burning sub-bituminous coals, Mr. Snell does not show why these units should be considered representative or similar to the Dry Fork unit. For example, the following aspects, which directly affect the NOx emissions of these units and how these NOx emissions can or cannot vary over time, are not considered:

> -Are these units baseloaded, like Dry Fork, for the period that the NOx emissions are reported? Since this factor alone will affect the extent of variability of NOx emissions, is should be discussed before making a claim of representativeness.
>
> -What are the types and ages of the combustion controls such as burner design, over-fire air system design, etc. at the chosen units and at Dry Fork? These comparisons will affect the NOx emissions from the boiler and are therefore directly relevant to the analysis before proclaiming that these units are representative.
>
> What is the vintage of the SCR units at these plants? Who are the suppliers of the SCR catalysts? What are the types of catalysts? How long have the catalysts been in use?

These, and other parameters that affect the variability of NOx emissions should be discussed before using data from these units are used as a basis for determining "reasonable margin."

10. With regards to in-boiler NOx emissions, Mr. Snell discounts the technical papers put forth by boiler vendors showing that boiler NOx emissions for Dry Fork could be lower than 0.25 lb/MMBtu.[16] He discounts these papers by arguing that short term performance tests may not be representative of NOx emissions that are achievable under all normal operating conditions. Mr. Snell is correct that these results are based on performance tests in many cases. Performance tests are not, by design, intended to be long term. However, the emission control rates achieved during performance test apply for all normal boiler conditions, as discussed in the technical papers. Mr. Snell has not provided any support for rejecting this information. Furthermore, because the Dry Fork boiler will be a base-loaded unit with a very high capacity factor, i.e., with close to steady state operations, there will be relatively little fluctuation in NOx emissions over time. Accordingly, the performance tests are good indicators of achievable emissions rates over the long term in this case. Because burner technology today can achieve values of NOx below 0.25 lb/MMBtu, this rate is not BACT for Dry Fork Station.

11. The fact that lower in-boiler NOx emissions are currently achievable with combustion controls is further supported by EPA in recent rule-making. For example, the Final BART Rule notes that the presumptive NOx limits for existing sub-bituminous units is 0.15 lb/MMBtu, without installation of post-combustion technologies such as SCR.[17] The Dry Fork BACT limit of 0.05 lb/MMBtu corresponds to a reduction of only 67% using SCR. However, most SCRs operate at or above 90% reduction efficiency. Therefore, a NOx emission limit lower than 0.05 lb/MMBtu is achievable for the Dry Fork Station.

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[15] Snell Report, p. 38-39.
[16] Snell Report, p. 40.
[17] 70 FR 39172, July 6, 2005. This rule requires that large stationary sources that are BART-eligible to include demonstrated technologies to reduce their emissions and therefore reduce regional haze.

12. Mr. Snell's assertions that combustion strategies designed to limit NOx formation also tend to increase the formation of CO and VOCs,[18] do not reflect current technologies in burner design. While this trade-off may have been an issue in earlier designs, that is not the case today. Most burner vendors have designs that reduce NOx emissions without increased CO (or VOC) emissions.[19]

15. Mr. Snell also notes that NOx guarantees by vendors may also be accompanied by "[a]mmonia slip guarantees that are too high."[20] However, Mr. Snell does not provide any vendor information or explanation for what he considers "too high." Furthermore, while there may be the possibility of formation of salts such as ammonia sulfate etc., the likelihood of such salt formation is lower for units burning sub-bituminous coals, such as Dry Fork, because of the generally lower sulfur contents of such coals.

16. Mr. Snell states that a SCR removal efficiency of 90% "would represent the performance target for a unit with boiler NOx emissions significantly greater than 0.25 lb/MMBtu," and that he is "not aware of any SCR vendors that would provide a commercially viable guarantee for 90% NOx removal at an inlet loading rate of 0.15 lb/MMBtu, with acceptable NH3 slip and adequate compliance testing."[21] There is no evidence that SCR vendors were contacted or were unwilling to provide such guarantees. Furthermore, Mr. Snell does not explain what he means by "acceptable" ammonia slip or "adequate" compliance testing or provide numerical values. Achieving a particular level of NOx reduction is a design issue, given inlet conditions. As demonstrated in my Expert report, SCR vendors can provide SCR designs in excess of 90% NOx removal. The corresponding levels of ammonia slip and testing must be part of the vendor documentation so that an informed decision relating to SCR design and selection can be made.

Furthermore, even if 90% removal of NOx resulted in unacceptable ammonia slip, Mr. Snell did not address 85% or 80% or even 75% removal. With boiler NOx levels at 0.15 lb/MMBtu, even 80% SCR reduction would translate to a NOx level of 0.03 lb/MMBtu, a level considerably lower than that proposed as BACT for Dry Fork.

B. SO2

17. Mr. Snell notes that the emission rate of 0.062 lb/MMBtu is the emission rate "very close to the design limit of the flue gas desulfurization control system, and provides essentially no margin."[22] However, Mr. Snell does not provide any documentation or other support to back up his assertion. He fails to explain the design basis that supports this level of SO2 emissions from the (presumably, dry) FGD system. Similarly, Mr. Snell asserts that "S&L concluded that the most aggressive design…for wet FGD…would be in the range of

[18] Snell Report, p. 41.
[19] See, for example, http://www.babcockpower.com/index.php?option=products&task=viewproduct&coid=21&proid=79.
[20] Snell Report, p. 42.
[21] Snell Report, p. 43.
[22] Snell Report, p. 35.

approximately 0.054 lb/MMBtu."[23] There is no explanation of the basis of S&L's conclusion. It is unclear what type of wet FGD or what type of reagent was assumed. These and other questions pertinent to the actual types of wet FGD that may have been considered are necessary to determine the design limits.

18. Mr. Snell refers to at least two different baseline values (presumably uncontrolled) of SO2 emissions from the boiler. On page 47 of his report, he notes that the baseline emission rate is 0.82 lb/MMBtu.[24] On the very next page he notes, however, that the uncontrolled SO2 emission rate is 1.21 lb/MMBtu.[25] While Mr. Snell notes that from a base of 1.21, the design target rate of 0.054 lb/MMBtu represents a removal efficiency of 95.5%, I note that, from a base of 0.82 lb/MMBtu, the same 0.054 lb/MMBtu represents a removal of 93.4%.

19. Mr. Snell asserts that "using a higher baseline SO2 emission rate has no effect on the incremental cost effectiveness calculation."[26] In my opinion, this is incorrect. Use of a higher baseline SO2 rate or higher sulfur rate will increase the absolute number of tons of SO2 that will be removed by each of the technologies, assuming similar removal efficiencies. It will also therefore increase the value of the difference in the number of tons removed between the two technologies, and therefore change the incremental cost effectiveness.

20. Mr. Snell discusses the impact of lower SO2 concentrations on SO2 removal efficiency in his report in general terms, with no reference to quantitative data or specific FGD designs.[27] Any decrease in control efficiency as a result of inlet SO2 concentration decreases will depend on the design and operating conditions of the FGD. Mr. Snell has not provided information regarding the actual SO2 concentrations in the boiler-out gas stream or vendor discussions showing the level of removal that can be achieved for different FGD designs. While he does not directly note the boiler-out SO2 concentrations at Dry Fork, he implies that it is around 550 ppm.[28] However, 98% or even 99% removal is possible at this level of inlet SO2 to the WFGD as demonstrated by the various FGD designs and operating data in my Expert Report. Notwithstanding, even if 98% were not possible because of inlet SO2 concentrations, there is still a significant difference between 98% and Mr. Snell's assumption of 95.5% in his WFGD basis. Therefore, a higher level of SO2 removal is achievable at the Dry Fork Station.

21. I provided several examples of wet FGD designs that have demonstrated at least 99% reduction of SO2 removal, many under long term conditions. Mr. Snell objects that most of these examples were achieved during short-term performance tests. However, there are no aspects of the design and operation of these units that would affect long term performance. In fact, several of these units have achieved longer term results that still show high values of SO2 removal. Mr. Snell discusses recent performance of the Mitchell unit. The performance data I referred to in my Expert report for this unit was achieved over 20 years ago as a result of installation of a WFGD on this unit pursuant to a consent agreement by the unit operator. The

[23] Snell Report, p. 48.
[24] Snell Report, p. 47.
[25] Snell Report, p. 48.
[26] Snell Report, p. 46.
[27] Snell Report, p. 50-51.
[28] Snell Report, p. 51. "…concentration of 2219 ppm…that is more than four times the inlet concentration expected…on the Dry Fork system…"

WFGD was subsequently either removed or became non-operational. Thus, comparisons to more recent data (i.e., since 1995) from this unit are not relevant.

22. Mr. Snell also argues that performance tests may not be representative of long-term operation because "WFGD control systems are not steady-state systems, [and] the controlled SO2 emission rate will fluctuate."[29] Because the Dry Fork unit is going to be a base-load unit, however, it will be as close to a steady-state operation as is practical. That is also true of its air pollution control systems. Thus, emissions fluctuations from Dry Fork should be much smaller than non-base load units. Accordingly, the compliance margin for Dry Fork should not be large and individual performance tests are representative of long-term operation.

23. Mr. Snell states that "a WFGD system would require at least 30% more water than a dry system, or approximately 200 million gallons per year."[30] He does not provide any of the underlying engineering calculations for verification. 200 million gallons per year corresponds to 380.5 gallons per minute (gpm) based on continuous usage. Thus, Mr. Snell seems to imply that the wet system will require 380.5 gpm more than a dry FGD system. He also implies (since the 200 million gallons is "30% more water") that the dry system's water usage is 1268 gpm. For a different project,[31] I, along with others, investigated water needs for dry and wet systems. In that instance, for units of roughly 590 MW (i.e., bigger than Dry Fork), the makeup water for the dry scrubber was around 341 gpm (i.e., far smaller than Mr. Snell's implied number) and the corresponding makeup water usage for WFGD was 430 gpm. The difference, in this case was 430 gpm – 341 gpm or 89 gpm. Scaling to the smaller unit size for Dry Fork, would make this difference even smaller. Assuming 422 MW for the Dry Fork plant and 590 MW for this example, the incremental water usage is estimated at 64 gpm.

24. Mr. Snell also quotes from a proposed EPA rule-making for mercury in which EPA was inviting comment as to Best Demonstrated Technology (BDT) for removal of mercury in sub-bituminous coals. In that proposal,[32] EPA suggested a bright line of 25 inches of annual precipitation to demarcate different BDT's for mercury removal. This EPA proposal was in a different context and subject to different legal and regulatory requirements. In this case, the rejection of wet FGD as BACT should be based on local conditions – such as incremental water needs and actual water availability, including all water resources in the area, and the benefits from increased SO2 removal by wet FGD. Campbell County has significant water resources[33] – including at least three perennial rivers (Cheyenne, Belle Fourche, and Power), numerous perennial surface water streams, significant annual precipitation (16.7 inches annually) and significant annual snow loading (66 inches annually). Therefore, the area can accommodate an incremental water use of 64 gpm.[34]

[29] Snell Report, p. 53.
[30] Snell Report, p. 55.
[31] Expert Report prepared for TXU (now Luminant) proposed plants in Texas (attached as Exhibit 8)
[32] 70 FR 62213, October 28, 2005
[33] Campbell County Multi-Hazard Mitigation Plan, date unknown (attached as Exhibit 9).
[34] The average per capita water use is roughly 172 gallons per day. See http://www.aquacraft.com/Publications/resident.html. Based on this, the incremental water usage at issue is the water usage for 536 persons.

25. These opinions are based on the information available to me at this time. If additional information is made available, I reserve the right to supplement my opinions.

I declare under penalty of perjury that the statements in this report are true and accurate to the best of my knowledge.

July 1, 2008___________ Ranajit Sahu

Date Dr. Ranajit Sahu