From: "Fickas, Justin" <JDFICKAS@mactec.com>
To: Purva.Prabhu@dnr.state.ga.us; Furqan.Shaikh@dnr.state.ga.us
CC: James.Capp@dnr.state.ga.us
Date: 1/18/2010 11:25 AM
Subject: Plant Washington Air Permit Comments
Attachments: H2SO4 Comments.DOC; NOx Comments.DOC; Plant Washington IGCC Analysis.DOC; P
M2 5 Comments.DOC; PM Comments.DOC; SO2 Comments.DOC; VOC Comments.DOC

Dear Mr. Shaikh:

The attached material has been developed at the request of our client, Power4Georgians (P4G). The attached documents relate to information that cover responses to comments received by EPD regarding the draft air permit. To the extent that the data included in this response to comments represents new or updated information, please consider this submission an addendum to the original application.

If you have any questions please give me a call at (770) 421-3335.

Sincerely,
Justin Fickas
Sr. Engineer
MACTEC Engineering and Consulting, Inc.

<<H2SO4 Comments.DOC>> <<NOx Comments.DOC>> <<Plant Washington IGCC Analysis.DOC>> <<PM2 5 Comments.DOC>> <<PM Comments.DOC>> <<SO2 Comments.DOC>> <<VOC Comments.DOC>>

GreenLaw H_2SO_4 Comments – Section I Page 20-22:

Comment: *The application erroneously eliminates circulating dry scrubbers because they have not yet been demonstrated on a coal-fired boiler greater than 250 MW. Circulating dry scrubbers are currently being bid at up to 440 MW and suppliers claim there is no technical obstacle to a single-module CDS absorber up to 700 MW. Ex. 152. Regardless, two 425 MW units in parallel could be used at the facility. **(Ex 152)***

Response: Ex. 152 mentions that suppliers of CDS technology claim that there is no technical obstacle to a single–module CDS absorber up to 700 MW. This is simply a supplier's claim, however, and as such, it has yet to be demonstrated in practice. Nor is there any technical data to support this claim. In the United States, CDS applications are limited to two small units burning low sulfur coal, plus a 2 x 250MW installation in Puerto Rico. Three additional units (104 MW, 150 MW (equivalent) and 2 x 330 MW) are currently under construction in the US. CDS systems are closely coupled to the fabric filter since the CDS requires a high recirculation of ash from the fabric filter to the CDS reactor. This recirculation is normally accomplished using material moving equipment such as an air-slide. A fabric filter on a unit the size of Plant Washington will require two casings, and accordingly, two or more CDS reactors. With multiple CDS reactors, the capital cost and complexity of the CDS increases significantly. It should also be noted that the operating costs of a CDS are higher than a wet FGD, the CDS produces more waste product than a wet FGD, the CDS prevents the sale of ash products which results in more byproduct landfill waste, and the SO_2 capture rate of the CDS is lower than wet FGD. For all these reasons, CDS technology was properly eliminated from Plant Washington's BACT analysis for H_2SO_4.

Comment: *Step 3 fails to provide any technical basis for the ranking of the technologies that were selected. The control efficiency of the wet scrubber for H_2SO_4 will depend on its design and various operational parameters. However, these are not discussed. Similarly, the degree of reduction of H_2SO_4 using sorbent injection will depend on the type of sorbent selected, the injection rate, the location of injection, etc. These are not discussed either. Thus, there is no demonstration that the emission limit based on the maximum degree of reduction has been selected.*

Response: The effects of SCR catalysts selection, NH_3 Slip, and alkaline ash scrubbing on the control efficiency of the wet scrubber have been discussed in H_2SO_4 BACT in Section 4.3.7 of the application. In addition, Table 4-22 in the application shows the effects of the type of sorbents evaluated, location of sorbent injection, and the degree of H_2SO_4 reduction.

Comment: *The cost-effectiveness analysis provided by the applicant for rejection of wet-ESPs is unsupported. No design information for the wet-ESP provided. Clearly, the cost and expected performance of any control device will depend, at a minimum on its design. Yet, the capital cost of the wet-ESP is assumed to be $290 million and its efficiency is assumed to be 98%. As such, this, "analysis" should be set aside until supporting data are provided.*

Response: The WESP removal efficiency of 98% was selected based on an analysis of the available technologies, the limited experience of installing WESP on coal-fired boilers the size of

Plant Washington, and the anticipated permit limits for $PM_{2.5}$, H_2SO_4 mist, and condensible particulates. The particulate capture in a WESP can vary with the design (plate or tubular, for example), number of fields, specific collection area, field voltage, gas velocity, wetted surface provisions, washing, pH control, and other important design parameters. As the removal requirements increase above the 98% range, the WESP cost will increase exponentially. The cost of the Wet ESP unit of $290 million was also provided by a design engineering company familiar with the design and pricing of Wet ESP units. Since the environment in the WESP is highly corrosive, the cost includes the use of high grade corrosion resistant alloys for wetted components in the gas stream.

Comment: *There is simply no basis and no justification for the 0.004 lb/MMBtu BACT emission rate. We recommend a limit of 0.001 lb/MMBtu as being consistent with the BACT standard. As noted, many other facilities have been permitted with similar limits, lower than the applicant's proposed limit of 0.004 lb/MMBtu. The Newmont Mining plant in Nevada has a BACT limit of 0.001 lb/MMBtu. The NRG Parish Unit 8 in Texas has a limit of 0.0015 lb/MMBtu. The Santee Cooper Cross plant has a limit of 0.0014 lb/MMBtu.* ***(Ex 75, Ex 163)***

Response: The Newmont Mining plant in Nevada utilizes a dry scrubber system. Due to the process technology differences, the sulfuric acid mist control effectiveness of a dry scrubber system is superior to that of a wet scrubber system (such as Plant Washington), and comparisons of sulfuric acid mist emission levels between plants with these different technologies is a faulty comparison.

The NRG Parish Unit 8 facility has a sulfuric acid mist emission limit of 10.10 lb/hr, and utilizes a wet scrubber for control of SO_2 emissions. At the maximum rated heat capacity of the Unit 8 boiler (6700 MMBtu/hr), this lb/hr emission rate is equivalent to 0.0015 lb/MMBtu. A direct comparison of the draft permit emission limit of Plant Washington (0.004 lb/MMBtu) to a lb/hr emission limit converted to lb/MMBtu value based on the maximum capacity of the boiler, is a faulty comparison since the lb/MMBtu emission rate from Unit 8 could be higher than 0.0015 lb/MMBtu if the source was operating at a lower load, while maintaining compliance with an emission limit of 10.10 lb/hr.

Santee Cooper Cross Unit 3 and Unit 4 have an emission limit of 0.0014 lb/MMBtu on a 365 day rolling average, taken as part of a PSD avoidance limit. Both Unit 3 and Unit 4 utilize a wet scrubber for control of SO_2 emissions. Unit 3 conducted an initial performance test in January 2007 and had a 3-run average tested result of 0.00021 lb/MMBtu. However, Unit 4 conducted an initial performance test in July 2008 and had a 3-run average tested result of 0.003 lb/MMBtu. Therefore, although both boilers have the same emission limit (0.0014 lb/MMBtu) only one of the two boilers demonstrated compliance with this limit on a short term basis. This is a demonstration that the results of a singular performance test should not be taken as a clear indication of compliance with a low emission limit. The test report for Unit 4 is included on the Commenter reference CD as Commenter reference Ex 75.

GreenLaw NOx Comments – Section D Page 5-10:

Comment: *Modern boilers employ sophisticated burner and combustion management systems that serve to optimize overall combustion conditions and often result in 15-20% NOx reduction in the boiler itself. The record makes no reference to these technologies and their implementation as part of the BACT for NOx. The analysis is therefore incomplete.*

Response: Sophisticated burner and combustion management systems are an integral part of boiler system design and are part of proper combustion techniques. Such systems will be utilized at Plant Washington. Although not directly discussed during the NOx BACT, good combustion controls, including the management of fuel residence time, air-to-fuel ratios, and temperature in the combustion chamber, have been selected as BACT for the control of CO and VOC emissions. These management techniques, along with detailed maintenance and operation plans, will be essential to maintaining a low level of CO, VOC, and NOx emissions from the main facility boiler. Commenters cite to a website listing various white papers that appear to reference specific combustion techniques at other facilities. Without any indication as to what facilities or techniques commenters refer, it is impossible to provide a meaningful response to this comment.

Comment: *The application states, without any support, that the boiler-out NOx level will be 0.22 lb/MMBtu. This is wrong. Numerous PRB-fired coal boilers, currently operating (and operating since the last five years) have much lower boiler out NOx emission rates.* ***(Ex 145)***

Response: Commenters' challenge to the estimated boiler outlet NOx level overlooks the fact that a trade-off exists between the formation of NOx in the boiler versus the formation of CO and VOC. Where, as here, the permit requires stringent limits on CO and VOC emissions, managing the combustion process in a way that lowers CO and VOC emissions comes at the cost of greater NOx emissions at the boiler outlet.

The balance that must be struck between the formation of NOx versus CO and VOC can be explained as follows. Primary combustion zones are operated in a reducing environment subject to limitations due to ash fusion temperatures, formation of H_2S (which can cause corrosion of the tube surfaces), CO, VOC and other intermediates formed in a reducing environment, temperature, oxygen content, and other critical parameters. When the over-fire air is introduced, sufficient oxygen is available to complete the combustion, thereby limiting the formation of CO, VOC, and unburned carbon. The flame temperatures and amount of oxygen, however, are still sufficient to allow formation of NO, NO_2, and other dimers of NOx. Since wall-fired boilers have levels of burners arranged on opposing walls and the over-fire air is introduced above the burners, they tend to form more NOx during combustion than corner-fired boilers which burn the fuel in a fireball.

Because of the careful balance that must be struck between the emissions of NOx, CO and VOC, one cannot compare boiler outlet NOx levels at different facilities without also analyzing the CO and VOC emissions of those other facilities. Commenters have failed to offer any such comparison in this case. Instead, they simply cite to EPA's Acid Rain database and assume that because other facilities have achieved boiler outlet NOx levels below Plant Washington's 0.22 lb/MMBtu, then Plant Washington must also be designed to achieve similar low levels. Again, this short-sighted analysis falls well short of invalidating Plant Washington's estimate.

Plant Washington's 0.22 lb/MMBtu boiler outlet NOx estimate rests on the best information available to the engineering design company that will design Plant Washington. Plant Washington's engineers have reviewed a variety of boiler design parameters to generate their boiler outlet NOx estimate, including boiler type, size, and combustion type (wall-fired or corner-fired), amount of staging (separated over-fire air, booster over-fire air, etc.), fuel mixture, load, and requirements for control of CO and VOC. Plant Washington's boiler will be a state-of-the-art supercritical design with provisions that include staged combustion. With the range of conditions and fuels considered for Plant Washington and the low requirements for CO and VOC to be controlled by proper combustion techniques, an engineering design company for Plant Washington has estimated that the boiler outlet NOx will range from about 0.16 to 0.22 lb/million BTU. The final control of NOx will be by SCR which will be selected during the design phase of the project. The design will minimize boiler furnace outlet NOx while at the same time limiting the formation of CO, VOC, and unburned carbon (which will impact boiler efficiency) to ensure compliance with all permit limits.

Comment: *G.T. Bielawksi, et al., "How Low Can We Go? Controlling Emissions In New Coal Fired Power Plants," U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 20-23, 2001 Chicago, Illinois, U.S.A., Ex. 129. This paper states that "[f]or PRB coal, emission levels down to 0.008 lb/MMBtu NOx, 0.04 lb/MMBtu SO2, and 0.006 lb/MMBtu particulate with a high level of mercury capture can be achieved." **(Ex 129).***

Response: Commenters cite to the Bielawski, et al. paper as support for their belief that Plant Washington's boiler outlet NOx level is too high. This paper does not support Commenters contention for several reasons. First, this technical paper discusses how a facility could *theoretically* achieve a level of NOx emissions of 0.008 lb/MMBtu through the use of an SCR. The paper does not provide any data from an operating facility to suggest that such low levels of NOx emissions are actually achievable on a consistent basis. Second, the theoretical limits discussed in the paper ignore the impact on CO and VOC emissions that might accompany such a low NOx emission level. Nor does the paper discuss the increase in H_2SO_4 emissions that would occur due to the increased catalyst required to achieve ultra-low NOx emission levels from the SCR. The increased catalyst required due to flue gas maldistribution on large coal-fired units contributes to higher SO_2 to SO_3 conversion. Lastly, the theoretical NOx emission levels discussed in the paper are premised upon boiler outlet NOx levels of 0.16 to 0.31 lb/MMBtu. Plant Washington's engineering design company actually estimated a smaller range of boiler outlet NOx levels of 0.16 to 0.22 lb/MMBtu. Thus, to the extent this paper is in any way relevant to the boiler outlet NOx level issue raised by the Commenters, it supports Plant Washington's boiler outlet NOx level estimate.

Comment: *A. Kokkinos, et al., "Which is Easier: Reducing NOx from PRB or Bituminous Coal, Power 2003," Ex. 130. This paper discusses retrofits at Georgia Power Company's Plant R.W. Scherer Units 3 and 4 (which burn PRB coal) with separated overfire air. The paper shows that Unit 3 and 4 achieved 0.13 lb/MMBtu of NOx after the retrofit, with CO ranging from 114 to 121 ppm (3% O_2 basis). As such, this refutes the contention that low NOx levels can only be achieved with corresponding higher levels of CO (and VOC) emissions. **(Ex 130)***

Response: Commenters are incorrect to suggest that the Kokkinos, et al. paper somehow undercuts the fact that a trade-off exists between low boiler outlet NOx levels and low CO/VOC emissions. A close read of this paper actually supports the fact that such a trade-off exists. The following table from the Kokkinos paper summarizes the testing performance of retrofits at Georgia Power's Plant Scherer. It is evident from the data presented that as NOx emissions were reduced in Unit 3 and

Unit 4 (those units burning PRB coal) by 55-60%, CO emissions increased significantly, from 12 ppm to 114 ppm at Unit 3, and from 32 ppm to 121 ppm at Unit 4. This data therefore supports the claims made in the Plant Washington application regarding a trade-off between CO and NOx emissions. It is also important to note that Plant Washington CO emissions are anticipated at approximately 100 ppm at an emissions level corresponding to the draft permit limit of 0.10 lb/MMBtu on a 30-day rolling average.

Comparing NO_x reductions at Plant Scherer. For Unit 2, which fires Eastern bituminous coal exclusively, the addition of the SOFA system resulted in NO_x levels of 0.23 lb/mmBtu with less than 60 ppm CO and less than 9.5% unburned carbon (UBC). This was better than expected performance, considering the poor quality and less-than-optimum fineness of the coal fired, in addition to fuel imbalances. Post-retrofit emissions results for Units 3 and 4, which only fire PRB coal, were very similar; NO_x levels were generally less than 0.13 lb/mmBtu with less than 125 ppm CO and less than 0.5% UBC. Both units had similar fuel imbalances; Unit 3 also was saddled with coal of less-than-optimum fineness. For all three units, the test results suggest that if fuel imbalances can be reduced or eliminated, even lower levels of NO_x and CO—as well as higher boiler efficiency—could be possible, because excess air could be reduced. *Source: Babcock & Wilcox*

	Unit 2		Unit 3		Unit 4	
Number of mills in service	5		7		7	
Coal type	Eastern bituminous		PRB		PRB	
	Pre-test	Post-test	Pre-test	Post-test	Pre-test	Post-test
Gross MW	865	870	883	884	881	873
SH steam flow, klb/hr	6,205	6,012	5,791	5,865	5,859	5,721
RH steam flow, klbs/hr	5,726	5,531	5,332	5,396	5,273	5,149
SH steam temp, F	981	995	1,002	1,000	1,001	1,000
RH steam temp, F	1,002	1,005	1,000	1,001	1,006	1,000
Burner tilt, deg A/B	+6/+4	–5/–2	–4/–4	–5/–6	–5/–5	–3/–3
Excess O_2 @ economizer exit, %	2.8	3.7	3.4	3.3	2.8	3.1
NO_x, lb/mmBtu	0.33	0.23	0.29	0.13	0.33	0.13
CO, ppm @ 3% O	118	32	12	114	32	121
UBC, % C by weight	9.1	8.3	no test	0.2	0.07	0.1
Opacity, %	8	7	7	6	8	5

Comment: *Robert Lewis, et al., Summary of Recent Achievements with Low NOx Firing Systems and Highly Reactive PRB and Lignite Coal, Ex. 131: as Low as 0.10 lb NOx/MMBtu; Patrick L. Jennings, Low NOx Firing Systems and PRB Fuel, Ex. 132: Achieving as Low as 0.12 LB NOx/MMBtu, ICAC Forum 2002.* ***(Ex 131, 132)***

Response: Both references cited do not discuss in detail the corresponding CO emission levels achieved at these low NOx emission levels. The only discussion regarding CO emissions in Exhibit 131 is as follows;

TFS 2000^{TM}R represents the most aggressive NOx reduction firing system technology available that includes features to mitigate increases in unburned carbon in fly ash and increases in carbon monoxide emissions from units firing high and low rank coals, respectively.

The only discussion regarding CO emissions in Exhibit 132 is as follows;

Table 2 illustrates the lowest achieved NOx emissions rate for seven different utility boilers while firing PRB under Low NOx conditions. These emissions rates were achieved at the Maximum Continuous Rating while maintaining full design steam temperatures and CO emissions below 200 PPM (@3% O2).

As discussed previously, the draft Plant Washington CO emission limit of 0.10 lb/MMBtu on a 30-day rolling average is equivalent to approximately 100 ppm CO. Although Exhibit 132 suggests that the use of low NOx emission technologies could result in CO emissions below 200 ppm, that statement, alone, does not indicate that the same technologies could maintain similarly low NOx emissions while also reducing CO emissions before the 100 ppm threshold required in the draft Plant Washington permit. The NOx values provided in Table 2 of Exhibit 132 range from 0.09 to 0.12 lb/MMBtu. Without more detailed information on the corresponding CO emission levels achieved with these units, a direct comparison to Plant Washington cannot be made.

It is also important to note that the WA Parish Unit #7 facility was referenced in Exhibit 131 and Exhibit 132, and that facility was referenced as having year 2000 average NOx (lb/MMBtu) of 0.15 lb/MMBtu using Alstom Low NOx Technology and PRB coal. From January to September 2009, NOx emission levels from this unit, while utilizing SCR for control of NOx emissions, ranged from 0.04 to 0.05 lb/MMBtu on a monthly average basis. This would represent an SCR efficiency of 67-73%, despite the design goal of the SCR systems at WA Parish to achieve an outlet NOx emission level of 0.03 lb/MMBtu (*Texas Genco's NOx Reduction Program (August 27, 2004)*).

Comment: *T. Whitfield, et al., Comparison of NOx Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers, 2003 Mega Symposium, Ex. 133.* ***(Ex 133)***

Response: No direct quotations from this document are provided by Commenters regarding lower achievable NOx emission levels. A review of this document indicates that the reference is a detailed technical paper discussing the results of the NOx emission reduction strategies employed at Georgia Power Plant Scherer. Exhibit 133 is essentially the technical companion piece to the same Plant Scherer study summarized in Exhibit 130. Exhibit 133, as with Exhibit 130, clearly demonstrate the inverse relationship that exists between NOx and CO emission levels in the boiler: *i.e.*, as NOx emission levels for Scherer Units 3 and 4 decreased during the study, CO emission levels from those same two units increased. The following Figure 13 and 14 from Exhibit 133 clearly shows Scherer Unit 4 CO emissions increasing as boiler outlet NOx levels decrease during retrofit activities.

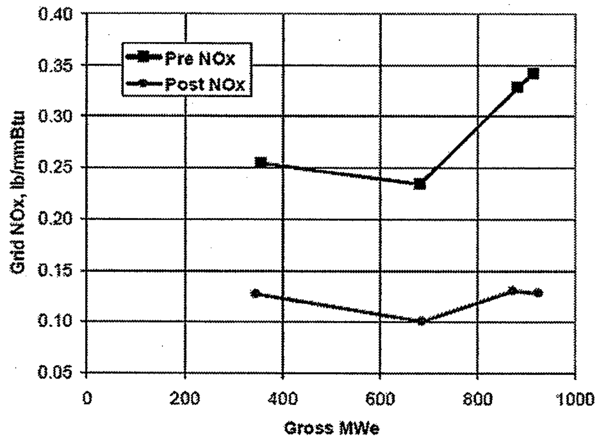

Figure 13 Pre- and post-retrofit NO_x vs. load, R.W. Scherer Unit 4.

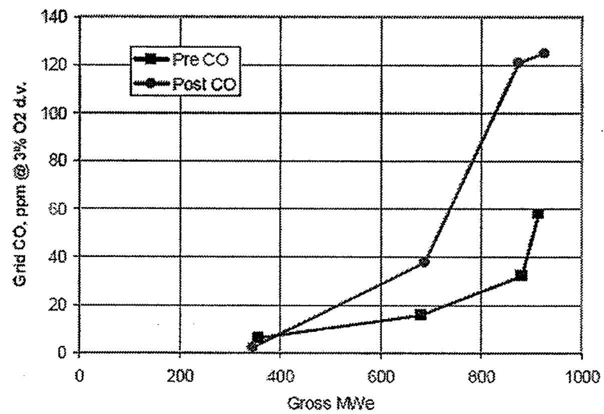

Figure 14 Pre- and post-retrofit CO vs. load, R.W. Scherer Unit 4.

Comment: *Galen Richards, et al., Development of an Ultra Low NOx Integrated System for Pulverized Coal Fired Power Plants, Ex. 134. "Baseline NOx emissions increased with coal rank 0.49, 0.56, and 0.66 lb/MMBtu for the PRB, hvb, and mvb coals., respectively. The optimized TFS 2000^{TM} firing system achieved NOx emissions of 0.11, 015, and 0.22 lb/MMBtu for the 3 fuels for approximately 70-75% reduction over the baseline NOx emissions. Additional NOx reduction of approximately 0.03 lb/MMBtu over the optimized TFS 2000TM levels was achieved using the Ultra-Low NOx firing system technology.* ***(Ex 134)***

Response: This reference is a brief executive summary document discussing the same technologies referenced in Exhibit 131 and Exhibit 132. As discussed in reference to Exhibit 131 and Exhibit 132, without more detailed information on the corresponding CO emission levels achieved with the units referenced, a direct comparison to Plant Washington cannot be made.

Comment: *Modern SCRs routinely achieve NOx removal efficiencies greater than 90%. Detailed analyses of EPA's Acid Rain Database indicates that "90% removal efficiency was currently being achieved by a significant portion of the coal-fired SCR fleet". Many coal fired units have been guaranteed to achieve greater than 90% NOx reduction and are achieving greater than 90% NOx reduction. The NOx BACT level that is appropriate for Plant Washington is 0.02 lb/MMBtu on a 30-day average basis.* ***Ex 135, 136, 137, 139, Footnote 14***

Response: As was fully explained in the Plant Washington application, the Applicant readily concedes that the SCRs at some facilities have achieved NOx removal efficiencies of 90% or greater. A review of the referenced Exhibit 135 indicates approximately 12% of the units reviewed achieved a NOx removal efficiency of 90% in 2004, while approximately 28% of the units reviewed achieved a NOx removal efficiency of 90% in 2005. These high removal efficiencies, however, have been achieved at facilities that have boiler outlet NOx levels that are much higher than the estimated level at Plant Washington. Commenters ignore this distinction, and instead suggest that high NOx removal efficiencies regardless of the boiler outlet NOx levels. The data simply does not support Commenters assertion.

The Applicant conducted considerable research regarding the NOx removal efficiency that can be expected by Plant Washington's SCR given the low boiler outlet NOx level estimated for the facility. That research, which is set forth in Table 4-7 and Figure 4-8 of Section 4 of the Plant Washington application, demonstrates a clear trend of decreasing SCR efficiency as the boiler outlet NOx level decreases. The application contains numerous examples to support this trend, including the four WA Parish units in Texas, which achieved uncontrolled NOx emission rates from 0.16 to 0.18 lb/MMBtu, but SCR control efficiencies from 72 percent to 77 percent. Following the installation of advanced low-NOx burner and OFA systems at the WA Parish units, SCR unit installation was designed to achieve an 80-85% reduction in NOx emission levels to achieve NOx emission values of 0.03 lb/MMBtu. However, these emission levels and removal efficiencies were not achieved following installation of the SCR units. This information was gathered through discussions with TCEQ air division personnel and review of technical literature regarding the WA Parish NOx reduction project. This is a clear demonstration the high SCR removal efficiencies observed at some facilities are not necessarily achievable at facilities with lower boiler outlet NOx levels.

The Commenters' own data further supports the trend described in the Plant Washington application. On page 8, footnote 14 of their comment letter, Commenters indicate that a review of NOx emissions data from EPA's acid rain database for 2006 indicate 9 units with SCR control efficiencies greater than 90% for units utilizing their SCRs during the ozone season. Table 1 is a summary of the data upon which Commenters statement is based.

Table 1: SCR Removal Efficiency Evaluation

Facility	January 2006 NOx Average Emission Rate (lb/MMbtu)	June 2006 NOx Average Emission Rate (lb/MMBtu)	SCR NOx Control Efficiency
Chesapeake Energy Center Unit 3	0.437	0.024	94.51%
John E. Amos Unit 1	0.541	0.031	94.27%
John E. Amos Unit 2	0.539	0.032	94.06%
Elmer Smith Unit 1	1.594	0.102	93.60%
Mount Storm Unit 2	0.618	0.04	93.53%
Dallman Unit 2	1.196	0.079	93.39%
Dallman Unit 1	1.191	0.081	93.24%
New Madrid Unit 1	1.361	0.124	90.89%[1]
New Madrid Unit 2	1.203	0.124	89.69%[1]

[1] Note: The SCR NOx control efficiency values indicated in Table 1 and found, following a review of the referenced data for New Madrid Unit 1 and New Madrid Unit 2, are lower than those provided by Commenters on Page 8 Footnote 14 (New Madrid Unit 1 and Unit 2 93.24%). January 2006 and June 2006 emission data obtained from the EPA Clean Air Markets website.

The average uncontrolled NOx emission rate for those units evaluated in Table 1 was 0.964 lb/MMBtu, with an average SCR NOx control efficiency of 93.02%. This data conforms with the data presented in Table 4-7 and Figure 4-8 of the Plant Washington permit application, which demonstrate a trend of increasing SCR efficiency with an increase in NOx loading to the SCR.

In sum, Commenters' assertion that the NOx removal efficiencies of greater than 90% observed at other facilities with higher boiler outlet NOx levels are achievable at Plant Washington is not supported by the available data. Nor is there any support in the data for Commenters belief that a NOx BACT limit of 0.02 lb/MMBtu could be "readily achievable" by maintaining a boiler outlet NOx level of 0.15 lb/MMBtu and a SCR removal efficiency of 87%.

Comment: *The application contains erroneous technical analysis pertaining to variability. This analysis notes that the nitrogen content of Wyoming coal can vary from 0.38% to 2.05% relying on the USGS Coal Quality Database. However, its own design basis shows that the PRB coal nitrogen content is 0.71% (normal) and 0.57% (abnormal).*

Response: The purpose of the variability analysis was to demonstrate that the NOx emissions from Plant Washington could be significantly impacted by the nitrogen content of the fuel, and any assessment establishing BACT limits should consider potential fuel variability impacts, not just regarding Plant Washington but also when assessing the emissions performance of other facilities. While the design basis nitrogen content indicated for Plant Washington is 0.57% to 0.71%, these values could still lead to a potential increase in NOx emissions of 0.005 lb/MMBtu, based on the assessment conducted on Page 4-40 of the Plant Washington permit application. While this may seem like an insignificant value, it represents 10% of the proposed NOx BACT emission limit of 0.05 lb/MMBtu.

Comment: *Even relying on the look-back approach to set BACT, the permit fails to set the correct BACT limit. As the application notes, "a total of 25 boilers are achieving levels equal to or below the proposed BACT level (0.05 lb/MMBtu)." Seven units achieved levels that were lower than 0.05 lb/MMBtu for the whole year 2007. At least two similar units (Walter Scott Unit 4 and Colbert Unit 5) achieved emission levels lower than 0.05 lb/MMBtu consistently.*

Response: Commenters erroneously claim that statements made in the application reflect flaws in the Applicant's "look-back" analysis. Commenters ignore the context in which these statements appear, which when fully considered, explains why these statements do not undercut the validity of the Applicant's BACT analysis. For example, Commenters note that the application states that "two similar units (Walter Scott Unit 4 and Colbert Unit 5) achieved emission levels lower than 0.05 lb/MMBtu consistently." What is not discussed by Commenters is that the Applicant closely evaluated the NOx emissions for these units and discovered monthly reported values as high as 0.048 lb/MMBtu for both units. Commenters similarly attempt to misconstrue the application's statement that "a total of 25 boilers are achieving levels equal to or below the proposed BACT level (0.05 lb/MMBtu)." Commenters fail to mention that while these 25 boilers may have achieved such levels in the calendar year 2007, the Applicant's exhaustive analysis of emissions from these same 25 boilers for the years 2002 through 2007 revealed that the historic emission levels from many of these sources approached or exceeded 0.05 lb/MMBtu. A summary of the Applicant's analysis was included in Table 4-5 and Figure 4-1 of Section 4 of the Plant Washington permit application.

Comment: *It is incorrect that there is a trade-off between lower NOx and lower CO values. Newer low NOx burners can achieve low NOx as well as low CO values.*

Response: As discussed in reference to Exhibit 130, Commenters are incorrect in their claims regarding a lack of a tradeoff between lower NOx and lower CO emissions. The combustion process is very complex. The boiler designer will design the combustion process to simultaneously control the CO and VOC emissions. As these emissions are decreased, the resultant NO_x will increase since control of VOC and CO are dependent upon fuel blend, flame temperature, combustion residence time, oxygen in the combustion zone(s), fuel to air ratio, mixing, boiler and burner design, etc. Low CO and VOC and low NO_x are competing mechanisms so a balance is chosen in the design.

Although a trade-off does exist between NOx and CO/VOC emissions, the Applicant does agree with the general proposition that new boiler designs, including the design that the Applicant plans for Plant Washington, can achieve low NOx emissions and low CO and VOC emissions as compared to older boilers. The stringent emission limits for NOx, CO and VOC set forth in the draft permit for Plant Washington will require the facility to achieve low emissions of all three pollutants. Accordingly, Plant Washington's boiler will be designed to effectively manage the trade-off between NOx and CO/VOC formation during the combustion process.

Comment: *The averaging time for the proposed NOx BACT limit of 0.05 lb/MMBtu (30-days) is not as stringent as the proposed NOx limit for the Taylor Energy Center which had a proposed limit of 0.05 lb/MMBtu but on a 24-hour average or the Trimble County Unit 2 which also has a NOx limit of 0.05 lb/MMBtu on a 24-hr average.*

Response: Information starting on Page 4-49 of the permit application discusses the justification for selection of a 30-day rolling average limit. Both the daily and 30-day rolling average emission values were evaluated for some of the higher performing NOx units, specifically the WA Parish Units and the Walter Scott Jr. Energy Center, Unit 4 (Figures 4-4 thru 4-7). These evaluations demonstrated that the 30-day rolling averaging compliance period selected was appropriate. For reference, the Taylor Energy Center was a proposed project in Florida whose application was withdrawn and the project did not receive a draft air permit. The Trimble County NOx emission limit, as discussed on Page 4-49 of the Plant Washington permit application, is 4.17 tons per day, which at the unit's maximum firing rate is equivalent to an emission limit of 0.05 lb/MMBtu. However, this limit would not match 0.05 lb/MMBtu when the boiler is operated at reduced loads, and is therefore not an effective basis of comparison to Plant Washington.

GreenLaw $PM_{2.5}$ Comments – Section G Page 15-19

Comment: *The applicant proposed a filterable $PM_{2.5}$ BACT emissions limit using particle size distribution data from AP-42, Table 1.1-6 for the case of coal combustion with a baghouse and its proposed filterable PM_{10} BACT limit of 0.012 lb/MMBtu. Hence, the filterable portion of $PM_{2.5}$ (as a fraction of PM) is assumed to be 53%. But this is inadequate. The filterable fraction as well as the control efficiency (and therefore the outlet emission rates) of the various sizes of PM, including $PM_{2.5}$, will depend on the type of bag materials that are selected. The company should have evaluated the various types of bags available in its top-down BACT analysis for $PM_{2.5}$. A bag leak detection system should also be considered as part of the BACT determination.*

Response: This comment overlooks the fact that the Applicant and the EPD both conducted independent evaluations of various types of baghouse bags. An analysis of the impacts of use of various types of filter bags was evaluated and discussed in the $PM_{2.5}$ BACT analysis as submitted to the Georgia EPD in May 2009 (Exhibit F), and was evaluated by the EPD as discussed in the Preliminary Determination Document (Page 35). Commenters also note that a bag leak detection system should have been considered as part of the BACT analysis. This comment makes no practical sense considering that Plant Washington will be required to utilize a Continuous Emissions Monitoring (CEM) system for filterable PM. A bag leak detection system is utilized as a surrogate monitoring strategy for excess PM emissions. Plant Washington will utilize a CEM system for direct measurement of total filterable PM. Continuous measurement of actual filterable PM emissions makes use of a bag leak detection system unnecessary. In any event, the Applicant understands that bag leak detection systems are part of the standard specifications for new baghouse units. It is therefore likely that the baghouse that is ultimately installed at Plant Washington will be equipped with baghouse leak detection systems.

Comment: *Other technologies that control PM2.5 emission exist and are readily available today. For example, a wet electrostatic precipitator (WESP) placed after a fabric filter would eliminate significant amounts of PM2.5 emissions.* ***Ex. 42****.The applicant failed to evaluate this combination of controls for PM2.5 BACT. EPA and others have recognized that wet ESPs reduce PM2.5 emissions.* ***Exs. 43 and 44****. Indeed, "the WESP is the ultimate device capable of . . . removing ultrafine particles."* ***Ex. 43 at 6-7****. Examples of facilities using wet ESP technology include: (1) Xcel Energy, Sherburne County, Units 1 and 2 (2) First Energy, Mansfield, Unit 2; (3) Duke Power, Cliffside, Units 6 and 7 (4) AES, Deepwater (operating since 1986),* ***Ex. 42 at 9, 10****; and (5)New Brunswick Power, Coleson Cove,* ***Ex. 43 at 6***

Response: The Wet ESP has been identified and evaluated as a $PM_{2.5}$ control technology in section 4.3.1 of the application, and was discussed in the PM2.5 BACT analysis submitted in May 2009 to the Georgia EPD. According to Mr. Hal Taylor, an individual hired by groups challenging the air permit issued to permit the Highwood Generating Station in Montana, "a wet ESP placed after the fabric filter would eliminate up to 99% of the filterable and condensable $PM_{2.5}$ emissions" (Ex. 42). Mr. Taylor, however, did not cite to any technical data or otherwise reliable source to support this statement, nor did he offer any other references in Exhibit 42 that would demonstrate the effectiveness of a

Wet ESP when installed after the fabric filters. The First Energy Mansfield Unit 2 site listed as using a Wet ESP actually utilized a Wet ESP unit for a short period during a pilot testing study, and does not use a Wet ESP for normal operation. The Cliffside Unit 6 and 7 listed as using Wet ESP are permitted units that have not yet been constructed. Use of Wet ESP units at the Xcel Energy, AES Deepwater, and New Brunswick Power sites was evaluated and discussed in Section 4.3.7 of the application.

Comment: *Power4Georgians improperly eliminated the Advanced Hybrid technology as not being available, but it was installed on a full-scale basis at Big Stone and, thus, is a commercially available technology (**Footnote 57 Page 18**).*

Response: The following are two quotes from the given reference by Commenters on the performance of the Advanced Hybrid Particulate Collector (*Demonstration of a Full-Scale Retrofit of the Advanced Hybrid Particulate Collector Technology*, February 2007), the first from Page 6 of the report (Executive Summary), and the second from Page 34 (Discussion of Results).

> *At the end of the project, OTPC decided to replace the Advanced Hybrid™ technology with a pulse jet bag house particulate removal system. Although the Advanced Hybrid™ showed the ability to remove particulate matter to very low levels, the expense of bag replacement and derates were determined to be unacceptable.*
>
> *Table 7 shows the derate history of the project. As discussed above, derates were a major problem and contributed significantly to the failure to demonstrate commercial viability. In short, the technology showed great promise for its ability to remove particulate matter in all size ranges. However, this demonstration showed that there are significant issues with the technology that, unless satisfactorily resolved, make it unlikely for the technology to have any success in the market place.*

As the above quote indicates, the very same document upon which Commenters rely demonstrates why the Advanced Hybrid Particulate Collector was properly eliminated from the BACT analysis for Plant Washington. The Commenters' referenced document discusses how Big Stone abandoned the technology due to technical issues with its operation, and that significant issues still exist with the technology and the demonstration project failed to demonstrate commercial viability. Therefore, the statements made in the Plant Washington air permit application regarding the commercial availability of the Advanced Hybrid Particulate Collector remain valid, notwithstanding Commenters' contention otherwise.

Comment: *A 2005 report prepared for the EPA listed numerous innovative control techniques that yield high $PM_{2.5}$ emissions reductions. Included in the list of controls are: (1) Compact Hybrid Particulate Collector **Ex. 44** (2) Indigo Particle Agglomerator, **Ex. 44, 45, 46** (3) Wet ESP, **Ex.** 47 and (4) Wet Membrane ESP, Ex. 44. Neither Power4Georgians nor EPD fully evaluated these technologies for limiting $PM_{2.5}$ emissions from Plant Washington.*

Response: Those control technologies listed by Commenters — Wet ESP, Indigo Particle Agglomerator, Wet Membrane ESP — were clearly discussed and evaluated in both the $PM_{2.5}$ BACT analysis prepared for Plant Washington (Exhibit F – May 2009), and EPD's Preliminary Determination document to the draft air permit (Page 31-35). The Compact particulate Collector (COHPAC) has been installed at the Gaston Plant near Birmingham, AL. The Compact Hybrid Particulate Collector indicated is a filter module installed downstream of an ESP as a "polishing filter". A well-designed fabric filter baghouse, as will be installed for Plant Washington, will have no need for a secondary "polishing filter".

Comment: *The company and EPD improperly relied on the BACT analysis for filterable PM_{10} and did not conduct an independent analysis of filterable $PM_{2.5}$.*

Response: Both the $PM_{2.5}$ BACT analysis prepared for Plant Washington, and the Preliminary Determination document prepared by the EPD, discuss additional control technologies specifically identified and evaluated for the filterable $PM_{2.5}$ BACT assessment (Table F-4 $PM_{2.5}$ BACT Analysis submitted May 2009, Draft Permit Preliminary Determination Page 32).

GreenLaw PM_{10} Comments – Section F Page 14-15:

Comment: *The total PM_{10} limit for Plant Washington established at 0.018 lb/MMBtu is inappropriate and should be reassessed. Important considerations such as the type of fabric filter, effects of filter cake buildup, etc. were not considered in the application.*

Response: Commenters contend that the draft Total PM/PM_{10} emission limit of 0.018 lb/MMBtu is inappropriate. However, an expert witness utilized by Commenters during the appeal of the Longleaf air permit stated that a total PM_{10} emission limit of 0.018 lb/MMBtu was appropriate as BACT for a pulverized coal-fired facility. Commenters contend that selection of fabric filter, effects of filter cake buildup, etc. were not considered in the application. However, these items were considered in preparation of the application, and discussed in detail in the $PM_{2.5}$ BACT analysis submitted to the Georgia EPD in May 2009.

Comment: *The filterable PM limit for Desert Rock is 0.010 lb/MMBtu, using CEMS. Yet, this was rejected simply because the facility has not yet been built at this time. This is not an adequate basis to reject a permit limit determined to be BACT by another agency, in this case the EPA.*

Response: The permit for Desert Rock facility contains a total PM limit of 0.02 lb/MMBtu, which is higher than the total PM_{10} limit of 0.018 lb/MMBtu determined for Plant Washington. Accordingly, Plant Washington's proposed PM limits together will be as stringent, if not more stringent, than the PM limits set forth in Desert Rock's permit. Commenters contend that the filterable PM limit for Desert Rock of 0.010 lb/MMBtu, using CEMS, was inappropriately rejected since it has not been built. However, what Commenters fail to consider is that the EPD has proposed a draft permit limit of 0.012 lb/MMBtu filterable PM/PM_{10} on a 3-hr rolling average, using CEMS, while the Desert Rock permit was issued a filterable PM emission limit of 0.01 lb/MMBtu on a 24-hr block average basis. In this instance, Commenters have inappropriately evaluated what was proposed by the applicant, and instead should have reviewed and commented on the determination as issued by the EPD, which is arguably more stringent than the Desert Rock permitted limit.

Comment: *Source test data (Exhibit 151) demonstrates that lower emission levels can be achieved. At least 147 performance tests at coal fired power plants in Florida, as early as May 2004, measured filterable PM/PM_{10} at less than 0.010 lb/MMBtu and 82 recorded PM/PM10 emissions less than 0.005 lb/MMBtu. The lowest reported PM/PM10 emission rate was 0.0004 lb/MMBtu.*

Commenters contend that source test data has shown that lower emission levels have been achieved. What is important to note is that the referenced stack tests (Exhibit 151) are short-term (3-hr) stack tests. Plant Washington will utilize a Continuous Emissions Monitoring system (CEMS) to continuously monitor filterable PM/PM_{10} emissions. Measuring of PM emissions on a continuous basis for Plant Washington will measure PM during issues such as soot blowing, load changes, scrubber mist carryover, fuel blend changes, etc. These issues were discussed in the May 28, 2009 letter submitted to the Georgia EPD regarding an evaluation of the filterable PM/PM_{10} emission limit, as well as comments made in regards to the draft air permit application as submitted on October 27,

2009. Therefore, direct comparison of short-term test results to a system that will be required to monitor compliance continuously, incorporating periods of transient conditions into monitoring, is not an accurate basis of comparison. Commenters note that 147 performance tests measured filterable PM/PM_{10} less than 0.01 lb/MMBtu. This value was actually 174 performance tests, instead of 147 performance tests, as shown in Exhibit 151. However, Commenters fail to point out that 127 performance tests showed results greater than 0.010 lb/MMBtu, with 98 performance tests with tested results greater than the draft filterable PM/PM_{10} limit for Plant Washington of 0.012 lb/MMBtu.

GreenLaw SO_2 Comments – Section E Page 10-14:

Comment: *There should be an explicitly stated permit limit for SO_2 of 0.019 lb/MMBtu on a 30-day and annual average basis.*

Response: Commenters conducted an assessment of the permit limits for Plant Washington, indicating that there should be an explicitly stated permit limit for SO_2 of 0.019 lb/MMBtu on a 30-day and annual average basis. However, as Commenters themselves note, if utilizing PRB coal matching the design specifications of Plant Washington and maintaining compliance with the minimum removal efficiency of 97.5%, these same emission levels will be achieved. Therefore, low emission levels of SO_2 in the range of 0.019 lb/MMBtu will be expected when utilizing PRB coal and maintaining compliance with the minimum removal efficiency of 97.5%. Maintaining compliance with a minimum removal efficiency value is essentially the same as establishing a specific lb/MMBtu permit limit for PRB coal when utilizing the average design basis PRB coal at Plant Washington.

Comment: *An SO_2 emission limit of 0.019 lb/MMBtu should be achieved regardless of the type of fuel utilized. The average normal sulfur content of the coal blend for Plant Washington is 1.72%, based on an average Illinois #6 coal sulfur content of 3.11%. The sulfur content of 3.11% is not reflective of washed Illinois #6 coal, since the value is so high. When incorporating proper washed coal values into the analysis, along with a high removal efficiency (99+%), SO_2 emissions of 0.019 lb/MMBtu are achievable regardless of the coal type used.*

Response: Contrary to Commenters claims, the Illinois #6 coal value is reflective of washed Illinois #6 coal. Commenters claim that coal washing removes 40% of the sulfur within the coal. However, coal washing typically removes 40% of the pyritic and sulfate forms of sulfur in the coal, with little to no removal of the organic sulfur content of the fuel. Raw Illinois #6 seam coal analyses indicate that average coal sulfur contents for raw Illinois #6 coals can be as high as 4.6%, with a pyritic sulfur content of 2.15%, a sulfate sulfur content of 0.15%, and a organic sulfur content of 2.30%. Applying a 40% removal to the pyritic and sulfate forms of sulfur provides a total Illinois #6 coal "washed" sulfur content of 3.68%. Also, Commenters provide no basis or references for a sulfur loss of 15% to bottom ash. Therefore, Commenters analyses on this issue are unsupported and in error.

Comment: *A 99.14% removal efficiency can be met based on current vendor designs and possibly using additives like dibasic acid, if needed (**Ex 142**).*

Response: Commenters' reference to Exhibit 142 does not support the contention that 99.14% removal efficiency can be achieved by the wet scrubber through the use of dibasic acid. Figure 6 of the referenced Exhibit 142 shows removal efficiencies of less than 99% achieved with addition of dibasic acid. Commenters also indicate that the removal efficiency of 99.14% could be met with current vendor designs. Since the minimum expected removal efficiency with use of high sulfur coals is 98.5%, then it is true that removal efficiencies of greater than 99% will likely occur on a short-term basis when utilizing a coal blend containing high sulfur coals. However, as illustrated in Figure 4-15 and Figure 4-16 of the Plant Washington application, a removal efficiency of 98.5% with use of high sulfur coals would be considered BACT performance, and emission limits with use of the higher sulfur content blend were derived from this value.

Comment: *Over twenty years ago, Mitchell Power Station Unit 3 (Alleghany Power), a 292 MW generating unit near Pittsburgh, was retrofitted in 1982 with a magnesium enhanced lime ("MEL") wet FGD system pursuant to a Consent Decree. Data is available for four months during 1983 and 1984 for that unit, and the maximum monthly average during these four months was 0.029 lb/MMBtu, corresponding to a 99.72% SO_2 reduction. Thus over 99% reduction of SO_2 was being achieved more than two decades ago **(Ex 143)**.*

Response: The limited data that is available for the referenced source does not demonstrate that SO_2 removal efficiencies as high as 99.72% are achievable on a long-term basis. No information was provided regarding the coal type (or characteristics of that coal) used in the analysis. From the data provided in Exhibit 143, the coal type was likely a bituminous coal due to the high uncontrolled SO_2 emission rate and presumed high coal sulfur content. As illustrated in Figure 4-15 and Figure 4-16 of the Plant Washington application, a removal efficiency of 98.5% with use of high sulfur coals would be considered BACT performance. A review of emissions data for the referenced unit from January to September 2009 as reported to the EPA Clean Air Markets Program indicated average monthly SO_2 emission rates ranging from 0.10 to 0.13 lb/MMBtu. Monthly data also reviewed for calendar year 1995 (the first year in the Clean Air Markets database that monthly data is available) indicated monthly SO_2 emission rates ranging from 0.09 to 0.16 lb/MMBtu. The emission unit referenced has therefore not maintained the high SO_2 removal efficiencies indicated on a long-term basis.

Comment: *A 2003 paper discussing the actual operating performance of the Chiyoda JBR or CT-121 wet scrubber technology in Japan notes that SO_2 removal efficiency of greater than 99% was achieved for all load levels and that a "[s]table SO_2 removal efficiency of over 99 percent was achieved". Additionally, Chiyoda's experience list shows at least three instances of 99% removal. **Ex 144***

Response: Commenters contend that the Chiyoda JBR, or CT-121 wet scrubber is a superior performing wet scrubber with SO_2 removal efficiencies greater than 99%. Commenters' own documents, however, indicate that the vast majority of operators of CT-121 wet scrubbers have not achieved 99% removal efficiency. For example, the internet source cited in footnote 32 of the comments indicates that only 2 (not 3, as Commenters contend) CT-121 units have achieved 99% removal. The other 46 CT-121 units listed by this internet source reported removal efficiencies that ranged from 82% to 98%. The Applicant's own investigation of several of these listed units confirms that 99% removal efficiency has not been continuously achieved by Chiyoda wet scrubbers. For example, a review of the Chiyoda scrubber performance at the installation at Killen Station Unit 2 in Ohio (Pages 4-101 to 4-103 of the Plant Washington application) indicated removal efficiencies less than 99% SO_2 removal. Similarly, an evaluation of the Chiyoda performance data for the referenced AEP Cardinal Units 1 & 2 also indicated less than 99% SO_2 removal.

The referenced exhibit (Ex 144) indicates that the Shinko-Kobe site uses a 0.93% sulfur coal at a heating value of 10,400 Btu/lb, providing an uncontrolled SO_2 emission rate of approximately 1.79 lb/MMBtu SO_2. At 99% removal, this provides an outlet emission rate of 0.0179 lb/MMBtu SO_2. Plant Washington, utilizing PRB coal with a design average sulfur content of 0.32% and a heating value of 8,500 Btu/lb, will have an uncontrolled SO_2 emission rate of approximately 0.75 lb/MMBtu. At the Plant Washington draft permit limit of 97.5% minimum removal efficiency, this provides an outlet emission rate of 0.019 lb/MMBtu. Therefore, the reported bottom line emissions performance of the Shinko-Kobe unit is not significantly different than that of Plant Washington.

Comment: *Mitsubishi Heavy Industries (MHI), another reputable vendor of wet scrubbers has a design called the High Efficiency Double Contact Flow Scrubber (DCFS), which has achieved SO_2 removal efficiencies as high as 99.9%. A presentation on the DCFS scrubber highlights the fact that it can be designed to achieve SO_2 removal efficiencies as high as 99.9% on a unit that burns high sulfur coals without the use of buffer additives. The manufacturer, MHI, guarantees SO_2 removal of 99.8%. A 2004 paper discussing the DCFS scrubber technology notes that this technology was recently selected at least two years ago by TVA for their Paradise Plant Unit 3, which will start up in early 2007. This paper also reports on several recent commercial operating successes with this technology —"including super high desulfurization performance (i.e., 99.9%) with a single absorber". The paper also notes that the COSMO oil Yokkaichi unit is an outstanding example of high SO2 removal by a single counter current DCFS. Commercial operation at COSMO began in 2003, and the FGD system has achieved a cumulative availability of 100% since startup. The system is designed at 99.5% and operates at 99.9% SO2 removal efficiency.* ***Ex 146 & Ex 147***

Response: Commenters identify the Mitsubishi Heavy Industries (MHI) Double Contact Flow Scrubber (DCFS) as a superior scrubber design. A review of the references provided by Commenters on these issues (Exhibit 146 and 147) provides the following information;

- The COSMO oil Yokkaichi unit and two facilities of a petroleum refinery company in Japan have achieved over 99% SO_2 removal performance under high inlet SO_2 concentration with DCFS scrubber. However, these facilities have petcoke and/or residue fired boilers and do not have coal fired boilers.
- Per the quoted references (Exhibit 146 and 147), the application of DCFS scrubber on coal-fired boilers in Japan have achieved SO_2 removal efficiencies only up to 96.3%
- The references provided indicate the first Greenfield DCFS system in the U.S. as being installed at the TVA Paradise Station Unit 3. An evaluation of DCFS performance at this facility was included in the Plant Washington air permit application (Pages 4-101 to 4-103), showing removal efficiencies less than 99%. An updated evaluation for data available for calendar year 2008 yielded the same result.

Comment: *A different variant of the wet scrubber technology –FLOWPAC – has demonstrated an SO_2 removal efficiency of over 99%. From November 2002 to March 2003, Karlshamn Unit 3 operated for 2152 continuous hours while firing a heavy fuel with an average sulfur content of 2.4%. The SO_2 emissions during this period were kept to 21 mg/Nm3, which is an SO2 efficiency of 99.5% with an S efficiency of 99%. During this period the FGD system was 100% available.* ***Ex 148***

Response:	A review of the indicated reference for this technology (Exhibit 148) indicated that the referenced Unit is located in Sweden, and that the Unit achieves 98% SO_2 removal continuously when firing 3.5% sulfur oil. The 3-month study referenced did find removal efficiencies up to 99.5% when firing 2.4% sulfur oil. However, these studies all focused on the use of oil and not coal as a fuel source. Therefore, the system performance when utilizing coal, based on the referenced study, is unknown.
Comment:	*Another vendor, Alstom, recently discussed high efficiency scrubbing on high sulfur fuels. As noted in the paper "[t]o date, the wet flue gas desulfurization system has achieved 100% availability while achieving the plant SO2 emissions limits throughout the operating duration . . . as indicated . . . the WFGD system has achieved SO2 removal efficiencies up to 99+% without the use of organic additives." **Ex 149***
Response:	The Meliti Echlada Electric Steam Plant in Florina, Greece is equipped with a limestone based, wet flue desulfurization (WFGD) system supplied by ALSTOM. The WFGD performance data at this plant shows that, the SO_2 removal efficiencies varied from 94.9% to 99.2%.The High removal efficiencies(above 99%) were achieved with inlet SO_2 loading of approximately 6,000 ppm. However, the WFGD data was available for only 3 days (12/9/03-12/11/03). This data fails to present any evidence that the 99% SO_2 removal efficiencies have been achieved over the entire duration of the ALSTOM WFGD operation. This data also fails to provide evidence that the 99% reduction would be applicable for all coals, including low sulfur coal, since the evaluations involved a unit utilizing lignite coal with a sulfur content ranging from 0.4% to 2.7%.
Comment:	*The Coal Utilization Research Council within the Electric Power Research Institute (CURC/EPRI) concluded in its September 2006 Roadmap that up to 99% SO_2 removal for FGD was commercially available in 2005. The CURC/EPRI Roadmap also projects removals of up to 99.6% in 2010 and 99.9% in 2015. **Ex 150***
Response:	Commenters include a reference (Exhibit 150) discussing a Roadmap regarding SO_2 removal efficiency provided by the Coal Utilization Research Council within the Electric Power Research Institute (CURC/EPRI). Commenters note that the Roadmap projects removals up to 99.9% by 2015. However, a table within the indicated reference shows a projected SO_2 removal of 98-99.9% by 2025. It is unclear where the value of 99.6% SO_2 removal by 2010 originated since this value does not appear within the referenced document (Exhibit 150). Details regarding the future technologies that would achieve the indicated SO_2 removals was not provided.
Comment:	*As to the 3-hour permit mass limit of 959 lb/hr, at the maximum heat input rate of 8,300 MMBtu/hr, this corresponds to 0.1155 lb/MMBtu. Even with the worst case (i.e., blend coal without coal washing and no loss to bottom ash), this implies that the scrubber would be operating at an efficiency of 96.7% SO_2 removal efficiency.*
Response:	Commenters discussions regarding the short-term emission limit are in error. Commenters indicate that the wet scrubber would be operating at an efficiency of 96.7% at the 3-hr permit mass emission limit of 959 lb-hr while utilizing the worst case coal. On Page 4-108 of the application, it is clearly stated that the worst case blended coal has uncontrolled SO_2 emissions of 4.62 lb/MMBtu. At full boiler load, 0.1155 lb/MMBtu, or 959 lb/hr, corresponds to a 97.5% removal efficiency of SO_2. Commenters note that, as stated by the applicant, the minimum expected removal efficiency for high sulfur coals

should be no lower than 98.5%. However, the removal efficiency evaluations included on Pages 4-101 to 4-108 of the application are long-term efficiency evaluations. On a short-term basis (i.e. 3-hr basis), it would be expected that SO_2 removal efficiencies could drop below 98.5%. Therefore, for establishment of a short-term emission limit, a minimum removal efficiency of 97.5% was assumed during use of the worst case coal blend (4.62 lb/MMBtu uncontrolled SO_2 emissions) to derive a short-term SO_2 emission limit.

GreenLaw VOC Comments – Section H Page 20:

Comment: *No trade-off exists between NOx and VOC emissions.*

Response: Commenters again argue that there is no trade-off between NOx emissions and CO/VOC emissions. As discussed in Section 4.3.2, 4.3.3, and 4.3.4 of the Plant Washington application, as well as previously discussed regarding comments to the NOx BACT analysis, a trade-off does in fact exist between NOx emissions and CO/VOC emissions. For those reasons previously discussed, Commenters' exhibits do not undercut this conclusion.

Comment: *The tradeoff argument is especially egregious for VOC because many facilities with lower VOC limits also have lower NOx limits than proposed for Plant Washington, e.g. Parish Unit 8; Toquop, Exs. 161A and 161B; Desert Rock, Ex. 162, and Trimble Unit 2.*

Response: The following Table is a summary of the VOC emission limits and corresponding NOx emission limits for those units cited by Commenters. Some of the data indicated in Table 1 was taken from Commenters' own referenced exhibits (Ex 161A, 161B, 162 for Toquop and Desert Rock). Data for Trimble Unit 2 was taken from facility permit information, while data for WA Parish Unit 8 was taken from State Implementation Plan (SIP) information for Texas.

Facility VOC and NOx Emission Limits Summary

Facility	VOC Emission Limit	NOx Emission Limit
WA Parish Unit 8	0.003 lb/MMBtu	0.045 lb/MMBtu[1]
Toquop	0.003 lb/MMBtu	0.06 lb/MMBtu 24-hr avg.[2]
Desert Rock	0.003 lb/MMBtu	0.06 lb/MMBtu 24-hr avg. 0.05 lb/MMBtu 30-day rolling avg.
Trimble Unit 2	0.0032 lb/MMBtu	0.05 lb/MMBtu 24-hr avg.[3]

[1] This emission limit is a State Implementation Plan (SIP) limit established to bring an area of Texas into attainment with air quality standards.
[2] The NOx emission limit for Toquop was discussed on Page 4-49 of the permit application.
[3] The NOx emission limit for Trimble Unit 2 is 4.17 tons per day, which equates to 0.05 lb/MMBtu at the maximum heat capacity of the unit. If the unit was firing at a reduced load the limit of 0.05 lb/MMBtu could be exceeded.

As shown, the facilities cited by Commenters all have either the same or higher VOC emission limits compared to Plant Washington, contrary to Commenters' claims. The NOx emission limit for Trimble County Unit 2 is 4.17 tons/day, which is equivalent to 0.05 lb/MMBtu on a 24-hr average when running at full capacity of the Unit. However, if the Unit were to run at a reduced load, the value of 0.05 lb/MMBtu could be exceeded. Therefore, comparison to the Trimble County Unit 2 emission limit is not a valid basis of comparison. Also, the 30-day rolling average NOx emission limit for Desert Rock is the same as that proposed for Plant Washington (0.05 lb/MMBtu). Therefore, Commenters' claims that the above-listed facilities have VOC emission limits lower than Plant Washington were in error.

Comment: *A well controlled boiler should be able to achieve low VOC and low NOx emission levels. There is no basis for rejecting lower VOC emission limits such as 0.0027 lb/MMBtu for the Intermountain Power Generating Station in Utah, Ex. 160, or the limit of 0.0024 lb/MMBtu for the Santee Cooper Cross Generating Station in South Carolina.*

Response: Initially, the Applicant agrees with the general proposition that a well-controlled boiler should be able to achieve low VOC and low NOx emission levels. The draft permit for Plant Washington will require just that - extremely low emission limits for both NOx and VOC. The Applicant disagrees with Commenters' claim that there is no basis for rejecting facilities with lower VOC emissions that have higher NOx emissions, such as Intermountain Power Unit 3 (VOC 0.0027 lb/MMBtu, NOx 0.07 lb/MMBtu 30-day rolling avg.), or Santee Cooper Cross Generating Station (VOC 0.0024 lb/MMBtu, NOx 0.08 lb/MMBtu annual avg.). Again, Commenters' argument rests on their unfounded belief that there is no trade-off between NOx emissions and VOC emissions. The Applicant has thoroughly explained why such a trade-off does, in fact, exist, and the Applicant has presented evidence from operating facilities to demonstrate that this trade-off does exist in practice. Based on Applicant's analysis (which Commenters cannot refute), it was entirely appropriate for the Applicant and EPD to exclude facilities with low VOC emissions but high NOx levels from further consideration in the Plant Washington VOC BACT analysis.