

Power4Georgians' Responses to Public Comments
Regarding the Case-by-Case Maximum Achievable Control Technology Analysis

This document contains Power4Georgians' responses to the comments raised by Greenlaw and the Southern Environmental Law Center in their October 27, 2009 letter regarding the Environmental Protection Division's (EPD) and Power4Georgians' case-by-case maximum achievable control technology (MACT) analysis for Plant Washington. Power4Georgians notes that many of the issues raised by the Commenters have previously been addressed in materials submitted to EPD over the past several years, and thus incorporates those materials to the extent they contain relevant information.

I. Response to Comments Concerning Adequacy of Filterable PM as a Surrogate for Non-Mercury Metal HAPs (Greenlaw Comment Letter Section III.B.1, pages 74-82).

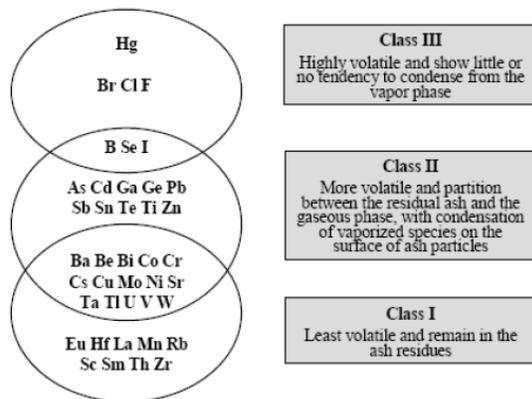
Comment: The notice of MACT Approval relies on filterable particulate matter (PM) as a surrogate for control of non-Hg metal HAPs. These elements are not all consistently present in particulate matter. Some are present as gases and as such are not removed by pollution-control devices that limit particulate matter. It is well known and widely reported that metallic HAPs fall into three classes. (Ex. 1, Ex. 2, Ex. 3, Ex. 4, Ex. 5, Ex. 7A, Ex. 7B)

*Response: At the outset, the applicable regulatory standard governing the use of a surrogate as MACT deserves a brief discussion. In the primary case setting forth the standard by which the appropriateness of a surrogate is adjudged, the U.S. Court of Appeals for the D.C. Circuit outlined four factors, the first of which asks whether the hazardous air pollutants (HAPs) at issue are "invariably present" in the proposed surrogate. *National Lime Ass'n v. EPA*, 233 F.3d 625, 639 (D.C. Cir. 2000). In *National Lime*, the HAPs at issue were metals, and as is the case in the Draft Permit, the proposed surrogate for those metallic HAPs was particulate matter, or PM. The U.S. Environmental Protection Agency (EPA) satisfied the "invariably present" factor of the Court's analysis by demonstrating that "where there is cement kiln PM, HAP metals are always in it, and when cement kiln PM is removed from emissions, HAP metals are always removed with it." 233 F.3d at 639. The Court upheld this rationale, noting that "as long as [EPA] demonstrates that there is a correlation between HAP metals and PM, it need not quantify that correlation or assess its variability because PM control technology is such that each unit of PM emissions avoided 'carries' within it some quantum of HAP metals." *Id.**

Commenters' statements and cited references do not rebut the fact that there is a correlation between the emissions of non-Hg metal HAPs and filterable PM such that where there is filterable PM in the Plant Washington emission stream, non-Hg metal HAPs are always in it. Instead, Commenters' statements regarding the "invariably present" prong of the surrogacy analysis attempt to "quantify the correlation" between emissions of non-mercury metal HAPs and filterable PM.

At best, Commenters' references suggest that *some* emissions of *some* non-mercury metal HAPs, most notably selenium, might not pass through Plant Washington's fabric filter control device in the particulate form. But again, as the D.C. Circuit recognized in *National Lime*, the relative strength of the correlation does not detract from the fact that non-mercury metal HAPs will be "invariably present" in filterable PM emissions from Plant Washington.

Commenters contend that metal HAPs, in particular selenium, arsenic, and chromium, should be regulated separately because these elements exist primarily in the vapor phase and would not be effectively captured by a particulate control device. The references cited by Commenters, however, do not support this contention (e.g., Commenters' Ex. 2, Ex. 4). The following figure is taken from Page 2 of Commenters' Ex. 4, titled *Toxic Emissions by Utility Coal Fired Boilers – Trace Metals in Combustion Systems (2008)*.



As can be seen in the referenced figure, chromium (Cr) is considered both a Class I and Class II element, while arsenic (As) is considered a Class II element and selenium (Se) is considered both a Class II and Class III element. Of greatest concern would be those elements considered Class III, or with little tendency to condense from the vapor phase. Therefore, Commenters' claims regarding arsenic, selenium, and chromium are unsupported by the provided documentation.

The temperature of the exhaust gas stream and the presence of other compounds (e.g., sulfur) in the exhaust gas will determine the condensation of non-mercury metal HAPs, including metal species such as oxides. These issues were discussed and evaluated in Commenters' Ex. 2, titled *Trace metal transformation mechanisms during coal combustion (1993)*. The following figures are Figure 3 (p. 179) and Figure 4 (p. 184) of that document.

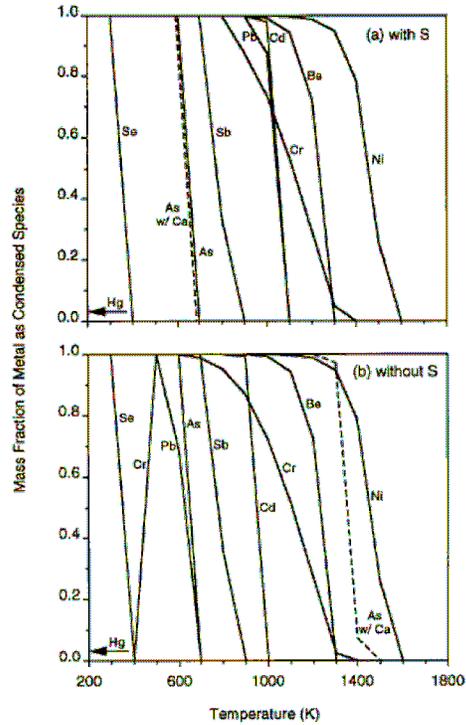


Fig. 3. Equilibrium predictions of condensed trace metal species as a function of temperature in a simulated coal fired utility boiler flue gas environment. Flue gas elemental concentrations calculated for an Illinois No. 6 coal and 20% excess air (Table 3) were used. Trace metal products considered are presented in Table 4. No metal/(metal or silicon) interactions were considered except as noted. Equilibrium predictions (a) with sulfur, and (b) without sulfur are included. Note that no condensed mercury species are predicted above 200 K.

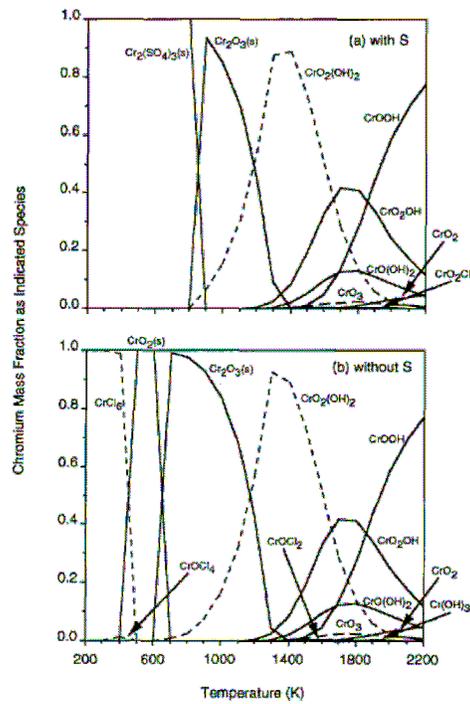


Fig. 4. Equilibrium predictions of chromium species as a function of temperature in a simulated coal fired utility boiler flue gas environment. Flue gas elemental concentrations calculated for an Illinois No. 6 coal and 20% excess air (Table 3) were used. Chromium products considered are presented in Table 4. No metal/(metal or silicon) interactions were considered. Equilibrium predictions (a) with sulfur, and (b) without sulfur are included.

As can be seen from the referenced figures, metal species evaluated, including arsenic and chromium but with the exception of selenium, are not in a vapor phase at temperatures less than 500 °K, or approximately 440 °F. Based on data provided by a design engineering company, the estimated flue gas exhaust temperature at the baghouse for Plant Washington will be between 310 °F to 350 °F, or 425 °K to 450 °K. Therefore, the information provided in Commenters' Ex. 1 suggests that the non-mercury metal HAPs, including both arsenic and chromium (but not selenium), should not be in the vapor phase by the time the exhaust gas reaches Plant Washington's fabric filter baghouse.

Commenters' references confirm the general proposition that while some non-Hg metals may be vaporized in the boilers, these metals will condense into particulate form as the flue gas cools in the control train. *See* Commenters' Ex. 1 at 225 ("The vaporized metals at high temperature near the combustion flame will subsequently nucleate or condense at a lower temperature downstream"); Commenters' Ex. 2 at 185 (same); Commenters' Ex. 3 at 8-5 ("It is mainly the temperature that dictates whether a certain trace element or trace element compound will be volatile."); Commenters' Ex. 5 at 2055 (same). To the extent any of Commenters' references present data documenting the distribution of trace elements in the boiler emissions, the data confirms that non-Hg metals will primarily (if not exclusively) be distributed in the bottom ash or the ash collected by the particulate control device. *See* Commenters' Ex. 1 at 222, Figure 1; Commenters' Ex. 3 at 8-7, Figure 8.5; Commenters' Ex. 5 at 2055, Figure 5.

As explained in Section 10 of the Plant Washington permit application, emissions of selenium will be effectively controlled under the operating conditions and with the pollution control technologies that will be installed at Plant Washington. The Wygen II example supports this conclusion. Initial compliance testing of the Wygen II facility in January 2008 indicated a testing average of greater than 98.8% removal of selenium per inlet/outlet testing of the facility baghouse. The Wygen II test was conducted using EPA's Method 29, which measures both gas phase and particle phase element concentrations.

Comment: *Mercury controls, including powdered activated carbon proposed to control mercury emissions from Plant Washington, have been demonstrated to increase the amount of chromium and nickel in stack gases, compared to no mercury control. (Ex. 4)*

Response: Commenters' Ex. 4 states that trace metal emissions are affected by temperature, flue gas constituents/coal chemistry, air pollution control devices, and sorbent/additives/conditioners. In the referenced document, the authors evaluate trace metal emissions with and without use of activated carbon injection (ACI). One of the facilities at issue in the study used an Electrostatic Precipitator (ESP) for PM control. Lower performance for the ESP unit could be explained by the activated carbon interfering with the ESP performance by decreasing the

conductivity of the ESP system, thus decreasing the particulate matter (and trace metals) collection efficiency. Additionally, although chromium and nickel concentrations did increase for another unit burning lignite coal, the overall removal efficiencies for those two metals remained over 99% at that unit. Any disparity in chromium and nickel emissions is therefore miniscule in relation to the high removal efficiencies achieved. Also, of the six units at issue in the study, the source that was most comparable to Plant Washington, a facility utilizing PRB coal and a fabric filter baghouse, showed greater than 99% removal of both chromium and nickel.

Comment: Some of the particulate HAPs are present in the condensable fraction of PM10. Condensable particulate matter must be included because the regulated non-mercury metallic HAPs are the metal “compounds,” e.g. selenium compounds, arsenic compounds.

Response: As discussed in response to a previous comment, the condensation of metal HAPs (including metal species such as oxides) depends on the temperature of the exhaust gas stream, as well as the presence of other compounds (e.g. sulfur) in the exhaust gases. Based on references provided by Commenters (e.g. Commenters’ Ex. 1), non-mercury HAP metals and metal species (with the potential exception of some amount of selenium) will not be present in the vapor phase at the Plant Washington baghouse under the expected flue gas conditions. Exhaust gas temperature conditions within the wet scrubber should be cooled sufficiently to assist in condensation and capture of any remaining vapor phase selenium (e.g. selenium compounds) in the exhaust gas.

What is also important to consider when discussing the use of PM as a surrogate is the monitoring method that will be utilized by Plant Washington, PM CEMS. A PM CEMS device will have the capability of detecting sub-micron particles. The two primary types of PM CEMS capable of being used in a wet stack following a wet scrubber are light scattering PM CEMS and Beta Gauge PM CEMS. Beta Gauge PM CEMS utilize a filter tape which will collect all particles greater than 0.1 microns in size. Commenters’ Ex. 5 provides data which demonstrates that the majority of selenium, arsenic, and chromium particles will exist at greater than 0.1 microns in size.

Comment: Power4Georgians asserts that referenced testing at the Wygen II facility demonstrates that those non-mercury metal HAPs evaluated were removed at high efficiencies and therefore existed in the particulate phase as PM. However, the test report specified otherwise. (Ex. 125)

Response: Initially, Commenters contend that the Applicant incorrectly reported the removal efficiencies of non-mercury metal HAPs, including cadmium, in the Wygen II

test. There is no merit to Commenters' claim. The following is Table 10-10 of the Plant Washington permit application.

Table 10-10 Wygen II Non-Mercury Metal HAPs Removal Efficiency Evaluation

Non-Mercury Metal HAP	Maximum Removal Efficiency ¹	Average Removal Efficiency
Antimony	93.4 %	93.0 %
Arsenic	99.3 %	99.1 %
Beryllium	96.6 %	96.1%
Cadmium	61.6 %	48.6 %
Chromium	99.5 %	98.7 %
Cobalt	99.2 %	99.1 %
Lead	99.5 %	95.9 %
Manganese	99.9 %	99.9 %
Nickel	99.6 %	99.2 %
Selenium	98.9 %	98.8 %

¹ Maximum removal efficiency indicated is the highest removal efficiency indicated for each of the three test runs of the removal efficiency evaluation. Testing conducted involved three test runs, with each test run of approximately 2-hrs resulting in 6 hrs of total testing. Boiler systems operated at maximum load (99 of 100 MW) during stack testing. Unit controls include SCR, dry scrubber, and fabric filter baghouse.

Prepared by: [PBS 6/18/08](#)
Checked by: [JDF 11/26/08](#)

Table 10-10 and the corresponding footnote to the table clearly indicate that the value of 61.6% was the highest cadmium removal efficiency found from each of the three test runs, with the average removal efficiency for cadmium of 48.6%. Commenters' challenge to the accuracy of the Applicant's representation of the Wygen II test results therefore should be disregarded.

Commenters also indicate that Power4Georgians failed to note that, although the Wygen II permit limits assumed 99.9% control of the metal HAPs, the test results showed less than 99.9% removal. Commenters fail to note that the non-mercury metal HAPs emission test results were consistent with the emission estimates provided in the permit application for non-mercury metal HAPs based on 99.9% removal (with the exception of antimony), even though 99.9% removal efficiency for non-mercury metal HAPs was not demonstrated. Commenters themselves question the reliability of the Wygen II testing data due to the fact that the inlet data was not collected at a location that met EPA Method 1, but the impacts of this on the testing results is unknown and could have affected the results either positively or negatively.

Comment: The particulate control device - a fabric filter baghouse, does not indiscriminately capture all HAP metal emissions because these HAPs are concentrated in the smallest particles, which are not efficiently collected by the proposed particulate collection device or because they are present in condensables. (Ex. 1, Ex. 2, Ex. 6, Ex. 7A, Ex. 7B, Ex. 8, Ex. 9, Ex. 10, Ex. 11, Ex. 12, Ex. 13, Ex. 14, Ex. 15, Ex. 16, Ex. 17)

Response: Commenters' claim that Plant Washington's baghouse will not indiscriminately capture all HAP metal emissions is not supported by Commenters' own references. For example, Commenters' Ex. 5, titled Fine particle and trace element emissions from an anthracite coal-fired power plant equipped with a bag-house in China

(2007), indicates that collection efficiencies of the particulate phase of trace elements are captured at greater than 99% down to the 1 micron range. The following is Figure 7 from Commenters' Ex. 5.

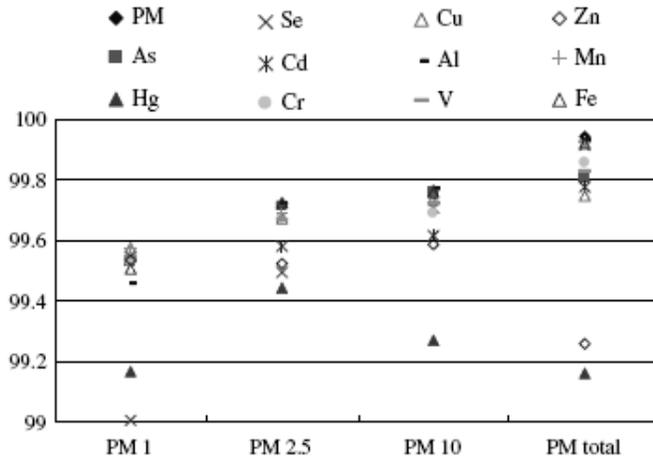


Fig. 7. The collection efficiencies of trace elements in different particulate size fractions.

The majority of references cited by Commenters (e.g. Commenters' Ex. 8) regarding the particle size of non-mercury metal HAPs are from the 1970s and early 1980s. A comparison of such data to Plant Washington, which will employ a modern coal-fired boiler with state-of-the-art emission controls, using the coal types as specified by Plant Washington, is not be an accurate basis of comparison.

Commenters contend that HAP metal emissions concentrated in the smallest particles will not be efficiently collected by Plant Washington's baghouse, yet on page 16 of the same document, Commenters contend that filtration media are available that allow 99.99% of the PM_{2.5} fraction to be removed. One of the references provided by Commenters, Ex. 17 – Figure 9, indicates that greater than 99% of submicron particles will be collected with a fabric filter baghouse. Another reference provided by Commenters, Ex. 16 (AP-42 Table 1.1-6), indicates a 97% collection efficiency of 1 micron particles using a fabric filter baghouse. Still other references cited by Commenters demonstrate that the fabric filter will effectively capture small particles. See Ex. 7A, Figure 7 (demonstrating that removal efficiencies for fabric filters remain uniform regardless of particle size); Ex. 7B at 13 (“Fabric filters have a very high removal potential and the removal efficiency is fairly constant even into the submicron particle size range.”). EPA research further supports this conclusion. In the Utility Report to Congress, EPA concluded that “[b]ecause of its high collection efficiency for small particles, the baghouse should be particularly effective for removing particles that have been enriched with HAPs.” EPA, Utility Report to Congress at 2-13.

Furthermore, it is important to note that while some of the non-mercury metals in Plant Washington's flue gas stream may be present in the PM_{2.5} fraction, the bulk of the material will be located in the PM₁₀ fraction. There can be no dispute that Plant Washington's fabric filter will obtain the highest removal efficiency of PM₁₀.

Finally, it should be noted that Commenters' proposed alternative surrogate, PM_{2.5}, fails to meet even Commenters' own standards for a surrogate. In contrast to filterable PM, there is no means of continuously monitoring PM_{2.5} emissions. As Commenters argue, "surrogate limits must be continuously monitored to serve as a continuous indicator of HAP emissions." Comment Letter at 81. The Applicant does not disagree with this statement, and for that reason believes that the use of PM_{2.5} would be a less stringent surrogate than the filterable PM surrogate in the Draft Permit. Filterable PM CEMS are readily available, reliable, and can provide operators with real-time monitoring capabilities that allow for a much more stringent means of ensuring compliance with emission limits. For all the foregoing reasons, Commenters' claim that Plant Washington's baghouse will not indiscriminately capture all non-mercury metal HAPs is without merit.

Comment: Different coals contain different quantities of metallic HAP but the same amount of ash, so that the particulate residue that results from burning different coals can contain more, or less, metallic HAPs. Accordingly, utilizing a cleaner coal (or less coal) can reduce metallic HAP emissions, without reducing particulate emissions (Ex. 18, Ex. 19, Ex. 20A, Ex. 20B, Ex. 20C, Ex. 21)

Response: Commenters suggest that Plant Washington could alter its coal supply to better control emissions of filterable PM. It is not commercially feasible for the Draft Permit to require Plant Washington to burn a particular coal from a particular mine. For the same reasons that the Applicant requested the flexibility to burn either PRB or a 50/50 blend of PRB and Illinois #6 coal (i.e., rail delivery interruptions), Plant Washington must maintain flexibility in its acquisition of coal from PRB and Illinois #6 coal mines. The low filterable PM limit that EPD has proposed will force Plant Washington to obtain coal that contains low quantities of ash.

Yet even if it was commercially feasible to specify that particular coal from a particular mine must be burned at Plant Washington, the Commenters' own data demonstrates why this is not necessarily a means of reducing emissions of non-mercury metal HAPs. For example, Commenters suggest that lower emissions of antimony, arsenic, cadmium, chromium, lead, and selenium could occur from use of coal from the Jacobs Ranch Mine as opposed to coal from the Cordero mine, due to the lower concentration of those elements from the Jacobs Ranch Mine coal analysis data (Commenters' Ex. 19). Commenters fail to point out, however, that concentrations of beryllium, nickel, and mercury are higher in the Jacobs Ranch Mine analysis data compared to the Cordero Mine data provided in

Commenters' Ex. 19. Utilizing a coal that would have the lowest concentrations of all non-mercury metal HAPs would be difficult, if not impossible, due to the number of constituents involved and the natural variability of these elements within different coal seams. This simple analysis also does not account for other factors (e.g. heating value of the coal) that would impact the uncontrolled emissions of non-mercury metal HAPs resulting from coal combustion. Accordingly, Commenters' suggestion that requiring use of a specific coal from a specific mine should be disregarded.

Comment: PM cannot be used as a surrogate for non-mercury metal HAPs because there is no relationship between ash content and trace metal content.

Response: Commenters also provide reference documentation which they claim suggests that there is no relationship between ash content and trace element content (e.g. non-mercury metal HAPs). A review of Commenters' Exs. 20A, 20B, and 20C indicates that the data involved was a limited data set which did not include any statistical correlation analyses between the ash and trace elements content. Therefore, no direct conclusions can be drawn from this data regarding any relationship between ash content and trace metals in coal. In fact, one of the references provided by Commenters (Ex. 21) states on Page 1 of the document that "The USGS trace element data for Pittsburgh seam coal samples from Pennsylvania were examined to determine correlations of ash and sulfur contents with trace element content. The data indicated moderate to strong correlations occur for the various trace element concentrations of the coals, and the contents of ash and sulfur." This reference therefore confirms that there is a relationship between ash content and trace metals concentrations in coal. For these reasons, Commenters' attempt to undercut the use of PM as a surrogate for non-mercury metal HAPs by questioning the relationship of ash content and trace metal content is not valid.

II. Response to Comments Concerning Use of Carbon Monoxide as Surrogate for Organic HAPs (Greenlaw Comment Letter Section III.B.2, pages 82-84).

Comment: Organic HAPs Are Not Invariably Present in Carbon Monoxide

Response: Commenters attempt to invalidate the use of CO as a surrogate by noting that organic HAPs are not present in CO emissions. Neither EPD, Power4Georgians, EPA, nor any of the other permitting authorities that have considered CO as an appropriate surrogate for organic HAP emissions have ever claimed that organic HAPs are present in CO emissions. As Power4Georgians made clear in its application, there are no known add-on controls to reduce emissions of organic HAPs. Commenters have furnished no claims or evidence to the contrary. Organic HAPs are, however, the product of incomplete combustion, as is CO. For that reason, efforts taken to reduce CO emissions will necessarily reduce

organic HAP emissions. See NESHAP for Reciprocating Internal Combustion Engines (RICE), 75 Fed. Reg. 9648 (March 3, 2010) (approving the use of CO as a surrogate for organic HAP emissions).

Comment: *Dioxin emissions form via distinct chemical reaction pathways are thus cannot be controlled through use of CO as a surrogate.*

Response: Commenters make numerous claims regarding the effects of chlorine and incomplete combustion on dioxin emissions, but do not provide sufficient information to support their claims. For example, Commenters claim that dioxin will be affected by chlorine emissions, with use of higher chlorine coals decreasing CO emissions but increasing dioxin emissions. In support of this claim, Commenters cite to slides from the Helsinki University of Technology. There is no author listed for these slides, nor is there any indication that the content of the slides has ever been subject to any form of peer review. The Applicant therefore has no means to independently verify the content of the slides. Nevertheless, even if this unverifiable internet printout could be viewed as a reliable source of information, it does not undercut the Applicant's proposed use of CO as a surrogate for organic HAPs. Commenters' Ex. 25 indicates that, for waste incinerators, controls including sorbent injection, fabric filter, and wet scrubbers can have a greater than 99% removal efficiency of dioxins. These same emission controls will be used at Plant Washington.

Comment: *CO Emissions lack the necessary "indiscriminating" correlation with organic HAP emissions and are not an adequate surrogate for organic HAPs. Combustion optimization will increase some organic HAPs, reduce some organic HAPs, and have no significant effect on certain other organic HAPs. (Ex. 24, Ex. 25)*

Response: The following is an excerpt from *Steam - Its Generation and Use, Edition 41, The Babcock & Wilcox Company*: "CO and VOC emissions are best controlled by employing prudent combustion system design and operating practices. The combustion system should facilitate good air/fuel mixing and allow for adequate residence time at required temperatures. Traditionally this has been referred to as the three Ts of combustion: time, temperature, and turbulence." Therefore, the assertions made by Commenters that CO emissions would decrease by use of bituminous coals is incorrect. Combustion controls on the boiler will limit CO formation regardless of the coal mix being used in the boiler.

As discussed above, there are three main factors (known as the three T's) that promote good combustion:

1. **Time:** Sufficient residence time in the combustion chamber to allow complete combustion.

2. **Temperature:** the temperature inside the combustion chamber must be high enough to combust all the fuel.
3. **Turbulence:** in the combustion chamber, turbulence must be such that air and fuel are well mixed so that no areas are oxygen starved.

Good combustion practices for boilers could be described as work practices and design principles. EPA has offered examples of these types of practice and principles in other MACT rules as follows:

- Providing adequate excess air with use of oxygen CEM and feedback air input control
- Providing adequate fuel/air mixing
- Homogenizing fuels (by blending or size reduction) to control combustion upsets due to high or low volatile content wastes
- Regulating waste and air feed rates to ensure proper combustion temperature and residence time
- Characterizing waste before burning for combustion-related composition (including parameters such as heating value, volatile content, liquid waste viscosity, etc.)
- Ensuring the source is operated by qualified, experienced operators
- Periodic inspection and maintenance of combustion system components such as burners, fuel and air supply lines, injection nozzles, etc.

In preparation of the Industrial Boiler MACT (Subpart DDDDD), EPA considered these factors and concluded there are so many interdependent parameters that affect combustion efficiency that they were not able to quantify good combustion practices. They concluded in the preamble of this rule that “consequently, any uniform requirements or set of work practices that would meaningfully reflect the use of good combustion practices, or that could be meaningfully implemented across any subcategory of boilers and process heaters could not be identified.” EPA chose to use an indicator parameter to measure the degree of combustion. CO, the parameter chosen by EPA, can be measured in stack gases and continuously monitored and recorded. Complete combustion of carbon results in carbon dioxide, so the presence of CO indicates incomplete combustion.

Commenters also claim that CO surrogate monitoring is inappropriate for organic HAPs. However, as discussed in Section 10 of the Plant Washington permit application, Page 10-61, EPA has previously recognized that monitoring of proper combustion through CO surrogate monitoring appropriate to demonstrate effective control of organic HAP emissions. *See* Hazardous Waste Combustor MACT, 64 Fed. Reg. 52828 (Sept. 30, 1999). A CO emission level of 100 ppm (equivalent to the 0.1 lb/MMBtu CO emission limit for Plant Washington) was determined in the Hazardous Waste Combustor MACT to ensure sufficient

organic HAP control. The following is an excerpt from the Hazardous Waste Combustor MACT.

We found that, in the vast majority of DRE test conditions, if a unit operated with carbon monoxide levels of less than 100 ppmv [parts per million by volume] and hydrocarbon emissions of less than 10 ppmv, the unit met or surpassed four-nines DRE. In some test conditions, units emitted carbon monoxide and hydrocarbons at levels less than 100 and 10 ppmv respectively, but failed to meet four-nines DRE. Most failed test conditions were either due to questionable test results or faulty test design.

Taken from Draft Technical Support Document for HWC MACT Standards (NODA), Volume II: Evaluation of CO/HC and DRE Database, April 1997.

64 Fed. Reg. at 52849. Therefore, monitoring of proper combustion will ensure effective control of organic HAPs, and will not lead to an increase in emissions of organic HAPs.

The EPA Hazardous Waste Combustor MACT also considered emissions of dioxins. The following are statements made regarding dioxins within that regulation:

Based on engineering information and principles, we identify temperature of combustion gas at the particulate matter control device of 400 °F or less as MACT floor control of dioxin/furan. This technology and level of control has been selected because postcombustion formation of dioxin/furan is suppressed by lowering postcombustion gas temperatures, and formation is reasonably minimized at gas temperatures of 400 °F or below.

The expected exhaust gas temperature at the fabric filter baghouse at Plant Washington, based on data provided by a design engineering company, is 310 °F to 350 °F. Therefore Plant Washington, through expected plant operating practices, will be minimizing post combustion formation of dioxins.

III. Response to Comments Concerning Filterable PM Limit (Greenlaw Comment Letter Section III.D.1, pages 88-93).

Comment: Even if particulate matter were an available surrogate for non-mercury metal HAPs, this proposed emission limit does not satisfy MACT. The proposed filterable particulate matter limit – 0.012 lb/MMBtu (3-hour average) is well above the emission rates being achieved in practice at similar sources. (Ex. 31, Ex. 32, Ex. 33, Ex. 34, Ex. 38, Ex. 65, Ex. 65, Exs. 67-76)

Response: Commenters provide data on numerous facilities from stack testing data, which they claim demonstrates that a lower filterable PM limit should be established for Plant Washington. Initially, it is important to note that data provided by

Commenters solely consists of short-term stack tests. Plant Washington will utilize a CEMS to demonstrate continuous compliance with a filterable PM/PM₁₀ limit of 0.012 lb/MMBtu, per conditions established in the Draft Permit. Therefore, continuous monitoring of PM emissions at Plant Washington will lead to monitoring of PM emissions during transient conditions (i.e. load changes, soot blowing) that are not necessarily accounted for in stack testing.

These issues were discussed in the May 28, 2009 letter to EPD regarding the proposed facility PM emission limit, as well as in the October 27, 2009 letter to EPD regarding comments submitted by Power4Georgians to the Draft Permit. Therefore, a comparison of stack test data to a unit utilizing CEMS for continuous compliance is not an accurate basis of comparison. Commenters provided no PM CEMS data to support their claims.

Even if the short-term stack tests cited by Commenters provided a reasonable basis for comparison with Plant Washington's CEMS-monitored filterable PM/PM₁₀ limit, Commenters' data suggests that the filterable PM/PM₁₀ limit in the Draft Permit is more stringent than the levels achieved at other facilities. For example, Commenters' Ex. 72, which sets forth the results of PM compliance testing for Weston Unit 4, indicated a tested value of 0.0147 lb/MMBtu, a value higher than the limit in Plant Washington's Draft Permit. Commenters indicate that over fifty stack tests in Florida recorded PM emission rates of 0.006 to 0.009 lb/MMBtu in Ex. 31. However, simply scrolling through this 270-page text file listing various emission source testing data reveals a significant number of tested results greater than 0.012 lb/MMBtu for fossil fuel-fired boilers. Similarly, Commenters' Ex. 151 included more than 90 source tests with a tested filterable PM values of greater than 0.012 lb/MMBtu.

Commenters also discuss that the filterable PM MACT floor should be no greater than 0.006 lb/MMBtu, based on a 3-hr average, and that this limit is consistent with conclusions by others. Commenters' Ex. 38 includes an analysis by an EPA Region 9 employee, Matt Haber, which indicates his belief that BACT for filterable PM as of 2002 at two existing boilers firing PRB coal and using a baghouse was 0.006 lb/MMBtu, monitored via Method 5 (stack testing) and continuously using triboelectric broken bag detectors. Initially, it must be noted that a report that contains an opinion submitted in an unrelated matter is not evidence of what constitutes MACT for Plant Washington. That is especially true for this reference, as Mr. Haber had to rescind portions of his testimony in that same matter, and more importantly, the court was ultimately not swayed by Mr. Haber's report.

Yet even if Mr. Haber's report constituted reliable evidence, it fails to support the position advocated by Commenters. For the pulverized coal-fired unit at issue in that matter, Mr. Haber determined BACT for filterable PM emissions to be 0.015 lb/MMBtu, a value much higher than the limit proposed by EPD and the Applicant for Plant Washington.

Comment: Other control options, such as fabric filter baghouse filtration media, Wet ESP, the Advanced Hybrid Particulate Collector, Indigo Agglomerator, etc. should have been considered by the applicant and EPD. EPD did not consider any of these technologies for limiting PM_{2.5} emissions from Plant Washington. (Ex. 41, Ex. 42, Ex. 43, Ex. 44, Ex. 45, Ex. 46, Ex. 47)

Response: Commenters offer a variety of critiques of the Applicant's consideration of PM control technologies, none of which has merit. First, Commenters claim that many technologies were not considered (Wet ESP, Indigo Agglomerator, etc.). However, these control technologies were discussed in the Plant Washington PM₁₀ and PM_{2.5} BACT analyses, and referenced in the Case-by-Case MACT analysis in Section 10 of the Plant Washington permit application. These technologies were also discussed in the EPD Preliminary Determination documents to the Draft Permit.

Second, Commenters suggest that EPD should require particular specifications at Plant Washington's fabric filter such as filtration media and air-to-cloth ratios. Baghouse technology is constantly evolving, such that a particular filtration media that obtains optimal performance today may be surpassed by better technology in just a few years. Given the construction schedule required to build a facility the size of Plant Washington, it makes little sense to require a particular baghouse specification today that may be obsolete by the time the baghouse is actually constructed for the facility. Furthermore, the selection of a particular component of a baghouse — e.g., the type of bag — can affect the performance of other control technologies at the facility. For example, Teflon-coating could interfere with the effectiveness of sorbent injection by limiting the formation of filter cake on the filter bags. The low PM limit in the Draft Permit coupled with the corresponding high PM removal efficiency Plant Washington will be required to achieve establish parameters that will require the Applicant to acquire and install the best filter bag technology available at the time the baghouse is constructed.

Third, Commenters suggest that EPD and the Applicant should have fully considered a Wet ESP in the MACT floor determination. It is well-established that fabric filters are the most effective PM control technology. EPA has recognized this fact, as have the authors of many of the references cited by Commenters. *See* EPA, Utility Report to Congress at 2-13. Commenters have referenced a number of facilities that have installed Wet ESPs. The Applicant's review of these facilities, however, indicates that the Wet ESPs were not designed or installed to control filterable PM. Moreover, the fact that these facilities have higher filterable PM limits than the 0.012 lb/MMBtu limit proposed by EPD for Plant Washington indicates that the use of a Wet ESP at the cited facilities was not determined to be capable of a filterable PM removal efficiency that would exceed the removal that Plant Washington will be required to achieve. For example, at Trimble Unit 2, BACT for PM/PM₁₀ was determined to be a fabric filter, not a Wet ESP. A Wet ESP was added for the control of sulfuric acid mist,

not PM. The filterable PM limit for Trimble Unit 2 was set at 0.015 lb/MMBtu, which is greater than EPD's proposed filterable PM limit for Plant Washington. Similarly, Dahlman Unit 4 installed a fabric filter as BACT for PM/PM₁₀. The Wet ESP installed at this unit was designed to control sulfuric acid mist emissions as well as the very high sulfur coal that facility was permitted to burn. Dahlman Unit 4's filterable PM emission limit is also 0.012 lb/MMBtu, and equal to the limit EPD has proposed for Plant Washington.

Commenters also reference Wet ESP use at AES Deepwater, Northern States Power/Xcel Energy station, and New Brunswick Power Coleson Cove facility. Commenters' own exhibits, however, indicate that the Wet ESP performance at these facilities is inferior to the performance that Plant Washington will be required to achieve through the use of a fabric filter. Specifically, the reference cited by Commenters that discusses these three facilities suggests that the Wet ESPs at these facilities have *lower* PM removal efficiencies as compared to the 99%-plus removal efficiency that Plant Washington's fabric filter will achieve. Commenters' references indicate that PM control achieved by the Wet ESP at AES Deepwater "is typically in the 95 to 97% range." Ex. 43 at 3. At the Northern States facility, "[p]articulate control exceeding 90% has been achieved..." *Id.* at 4. The Wet ESP installed at the New Brunswick Power facility was designed to remove sulfuric acid emissions, not filterable PM. In any event, the permitted PM limit for that facility is 0.015 lb/MMBtu and thus greater than EPD's proposed filterable PM limit for Plant Washington. *Id.* at 6. In sum, Commenters' references to the use of Wet ESPs at other facilities fails to undermine EPD's conclusion that Plant Washington's fabric filter will provide the most effective filterable PM control at Plant Washington.

The Commenters' reference to other technologies other than Wet ESPs is similarly unpersuasive. The Compact Hybrid Particulate Collector (COHPAC) has been installed at the Gaston Plant near Birmingham, AL. The Compact Hybrid Particulate Collector is a filter module installed downstream of an ESP as a "polishing filter" to achieve better performance than a system utilizing an ESP alone. A well-designed fabric filter baghouse, as will be installed at Plant Washington, will have no need for a secondary "polishing filter" since a fabric filter baghouse will provide the maximum degree of control for filterable PM emissions.

Commenters' own references also clearly demonstrate why EPD would never want to require an Advanced Hybrid Particulate Collector (AHPC) at Plant Washington. The very report cited by Commenters regarding performance of the AHPC concluded as follows:

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. (Comment Letter, p. 92, n. 216 at page 6)

...

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. (Note 216, page 34)

As these passages make clear, the AHPC is not a viable alternative to the fabric filter baghouse that will be installed at Plant Washington. In sum, Commenters' claim that the Applicant's analysis of alternative PM control technology was flawed is not valid.

IV. Response to Comments Concerning Carbon Monoxide Limit (Greenlaw Comment Letter Section III.D.2, pages 95-95).

Comment: The CO MACT floor limit should be no greater than 0.05 lb/MMBtu based on a 3-hr average, based on reviewed stack testing data. This is half of the value proposed by EPD as a MACT limit for organic HAPs and on a much shorter averaging time than the proposed 30-day averaging time. Neither Power4Georgians nor EPD provided any beyond the floor analysis of MACT for the organic HAPs to be emitted by Plant Washington. (Ex. 31, Ex. 32, Ex. 33, Ex. 34, Ex. 48, Ex. 49)

Response: Commenters incorrectly claim that no beyond the floor analysis was conducted by either Power4Georgians or EPD. Discussions on this subject were clearly made in Section 10 of the Plant Washington permit application and in Appendix A (Notice of MACT Approval) of the EPD Preliminary Determination.

Commenters cite stacks tests from several facilities as support for their contention that the appropriate MACT floor is 0.05 lb/MMBtu on a 3-hr average basis. Again, however, Commenters are attempting to compare results from one-time stack tests with a facility that will monitor CO emissions on a continuous basis through use of a CO CEMS device. Transient conditions that will occur during normal source operation, such as boiler load changes, will be accounted for and measured by a continuous monitoring system, but will not necessarily be accounted for in a 3-hour stack test. Commenters indicate that testing for the Cedar Bay site between 2003 and 2008 achieved an emission rate of 0.05 lb/MMBtu (Ex. 49). However, this data is only representative of less than 0.1% of the potential operating time of the Cedar Bay boilers evaluated.

Also, secondary considerations such as emission rates of other pollutants, such as NO_x, were not considered or discussed by Commenters. A review of data provided for other stack tests by Commenters (e.g. Exs. 33 & 48) indicate the low CO emissions that were observed occurred at facilities that had higher NO_x emissions than those set forth in Plant Washington's Draft Permit.

V. Responding to Comments Concerning Hydrogen Chloride Limit (Greenlaw Comment Letter Section III.D.3.a, pages 96-102).

Comment: The MACT approval fails to identify important design criteria for Plant Washington. Neither the MACT application nor the Notice of MACT approval reports the design basis coal chlorine content, which is essential to determine appropriate HCl MACT limits. Instead, the MACT application summarizes generic coal quality data for subbituminous and bituminous coals as reported in the U.S. Geological Survey COALQUAL database.

Response: There is no basis for Commenters's claim that the application fails to include the design coal basis data regarding coal chlorine content. Table A-2 (Page A-8) of Exhibit A to the permit application, titled Coal Design Data, includes data for the design coal chlorine content. Commenters contend that both sub-bituminous and bituminous coal chlorine content data was based on data from the USGS COALQUAL database. Again, Commenters' are mistaken. Table A-3 (Page A-31) of Exhibit A to the permit application clearly indicates in the footnote that the chlorine content of Illinois #6 (bituminous coals) was not based on data provided from the COALQUAL database, since there was limited data available in the database for the chlorine content of these types of coals. The chlorine content of Illinois #6 coals was based on discussions with coal experts familiar with the quality of coals from the Illinois basin.

Commenters argue that data provided by the USGS COALQUAL database for PRB coals should not be used because they claim it does not reflect the quality of coal that will be burned at Plant Washington. Setting aside the fact that neither the Applicant, EPD, nor the Commenters can know the exact specifications of any coal that will be burned at a facility that has not yet been built, much less permitted, Commenters fail to offer any evidence that would suggest that the coal design assumptions the Applicant used from COALQUAL are not representative of the PRB coals that may be available for purchase at the time Plant Washington commences operations. To the contrary, a comparison of the design coal chlorine content data provided in Table A-2 of the permit application (based on COALQUAL data) to coal analyses for various PRB coal mines (including data provided in Commenters' Ex. 19) reveals that the design coal chlorine data used in the Plant Washington application is consistent with coal analysis data from PRB coal mines. Commenters have no basis on which to criticize the Applicant's reliance on COALQUAL as the best available data set of PRB coal chlorine content. Commenters likewise lack any basis to suggest that COALQUAL data is

not sufficiently specific for purposes of the federal regulations governing Case-by-Case MACT applications. No such requirement exists in 40 C.F.R. § 63.43(e)(2)(viii).

Comment: *The MACT limits are less stringent than several other HCl emission limits for coal fired electric utility boilers. Emission limits for sources including the Longview facility in West Virginia and Trimble County are lower than those proposed for Plant Washington. (Ex. 53, Ex. 54)*

Response: The Applicant's investigation of the Longview and Trimble facilities indicates that neither of these facilities have the MACT limits claimed by Commenters. The Longview HCl limit cited by Commenters, 0.00001 lb/MMBtu (3-hour), is not the same HCl limit reported on EPA's RACT/BACT/LAER Clearinghouse (RBLC). The RBLC reports an HCl limit of 0.0021 lb/MMBtu. The Applicant contacted the West Virginia DEP permit engineer responsible for the Longview site, who reported that while the 0.00001 lb/MMBtu limit is the correct HCl limit, he indicated that the value was derived through a settlement, not through a MACT analysis. The Applicant's further investigation of the Longview permit indicates that the HCl limit was established in an attempt to avoid major source status for HAPs, and thus were not derived through a MACT analysis. For that reason, the Longview HCl limit is not representative West Virginia DEP's view of MACT. The HCl limit cited by Commenters for the Trimble facility is also not applicable to Plant Washington. Commenters indicate that the Trimble facility in Kentucky, using a blend of sub-bituminous and bituminous coals, has a lower HCl limit than proposed by Plant Washington at 0.0005 lb/MMBtu, 3-hr average (Ex 54). These statements are inaccurate. The 0.00005 lb/MMBtu limit cited by Commenters is the HCl limit for Trimble's *oil-fired auxiliary boiler*, and is based on the MACT standard for such sources set forth in 40 CFR 63 Subpart DDDDD. Commenters' Ex. 54 provides no listed HCl emission limit for the main utility boiler (Unit 2) at Trimble. For this reason, the Trimble limit cited by Commenters was properly excluded from further analysis by the Applicant.

Comment: *The MACT floor did not consider the best controlled similar source. Emission tests at facilities with wet FGDs found removals of both HF and HCl over 99%. Not only does 98.5% HCl control not reflect the best controlled similar source, but lower HCl emission rates have been achieved in practice. (Ex. 55, Ex. 56)*

Response: Commenters reference data used in support of the Duke Cliffside minor HAP permit determination (Commenters' Exs. 55 & 56) to indicate that greater than 99% removal of HCl is achievable. Commenters fail to note, however, that the referenced testing occurred while using a high chlorine content bituminous coal. The emissions performance of these systems using a lower chlorine content coal, such as sub-bituminous PRB coal, is unknown. The effect of the varying chlorine contents of the two types of coals on HCl emissions cannot be denied. Indeed,

Commenters readily concede that “emissions of HCl are determined by the chlorine content of the coal.” Comment Letter, page 96.

Moreover, the thrust of Commenters’ statements appears to be that the Applicant and EPD failed to recognize that certain tests of bituminous coal-fired units (Commenters’ Exs. 55 & 56) demonstrate that 99% removal efficiency is achievable. This comment ignores the fact that EPD lowered the effective HCl limit while using a 50/50 blend of bituminous and sub-bituminous coals to 1.36×10^{-3} lb/MMBtu. The estimated uncontrolled emission rate of HCl emissions from the 50/50 blend, based on coal design data for Plant Washington, is 1.93×10^{-1} lb/MMBtu. This means that the control efficiency of HCl emissions for Plant Washington when burning the 50/50 blend will now be *greater than 99% removal efficiency*. By Commenters own logic, then, EPD has required Plant Washington to achieve the maximum achievable HCl removal efficiency. In sum, Commenters’ claim that EPD and the Applicant failed to consider the best controlled similar source should be disregarded.

Comment: EPD improperly relied on permit limits in proposing bituminous coal MACT for HCl at Plant Washington. Permit limits are typically higher than actual emission rates. Stack test data demonstrates that lower emission limits are achievable. (Ex. 28, Ex. 58, Ex. 59)

Response: Commenters provide test data which they believe demonstrates that lower HCl emission limits are achievable at Plant Washington. A review of this data does nothing to undercut the HCl MACT limit EPD has proposed in the Draft Permit. Initially, Commenters fail to note that EPD identified several facilities in their review of the MACT floor facilities, including Wygen II and Newmont TS Power, that recorded stack test results (some as recent as 2008) with higher HCl emission rates than the draft HCl limit for Plant Washington while burning sub-bituminous coal.

The Applicant has also discovered numerous discrepancies in the stack test data Commenters’ have presented which undercuts the validity of this data. For example, Commenters cite a table in Ex. 28 (Table 2-6.2) that the Applicant could not locate in the document. The Table that the Applicant was able to locate in that same document, Table ES-1, included data for the Springerville and Baily sites, but did not include test data for the Shawnee, Burger, or Arapahoe sites. Data for the Boswell and Yates sites was located within the same document, but the values in the document differed from those referenced by the Commenters. For example, Commenters claim that the Boswell facility achieved an HCl emission rate of 0.0000011 lb/MMBtu. On closer review, Commenters’ Ex. 28 indicates that that same facility achieved an emission rate of 0.00079 lb/MMBtu. Therefore, the validity of the data provided by Commenters could not be confirmed.

Comment: EPD did not adequately consider beyond the floor controls for HCl control at Plant Washington. A chloride prescrubber could be used to remove additional HCl. A prescrubber could be used at Plant Washington to reduce HCl emissions below the levels achieved using only a wet scrubber.

Response: Commenters claim that a prescrubber could be used to reduce HCl emissions below the levels achieved using only a wet scrubber. Commenters fail to provide supporting data from references that support these claims. Documents referenced in footnote 230 of the Comment Letter discuss how chloride prescrubber systems could be used to convert power plants into “green” chemical producers of HCl. Commenters provide no evidence, nor is the Applicant aware of any, of a prescrubber being installed on a coal-fired electric generating unit like Plant Washington. Although the documents indicate that emissions from conventional hydrochloric acid manufacturing are significant, any secondary environmental concerns at the coal plant, which would now be producing HCl, are not discussed. Also, no data within the referenced articles could be located that would establish the removal efficiencies of such prescrubber systems, and thus no comparison could be made to the control efficiency expected from Plant Washington’s wet scrubber system. Commenters have therefore failed to provide sufficient information to support their claims regarding chloride prescrubbers.

VI. Responding to Comments Concerning Hydrogen Fluoride Limit (Greenlaw Comment Letter Section III.D.3.b, pages 102-105).

Comment: The MACT approval fails to identify important design criteria for Plant Washington. Neither the MACT application nor the Notice of MACT approval reports the design basis coal fluorine content, which is essential to determine appropriate HF MACT limits. Instead, the MACT application summarizes generic coal quality data for subbituminous and bituminous coals as reported in the U.S. Geological Survey COALQUAL database.

Response: Commenters again erroneously claim that neither EPD nor the Applicant have provided adequate design coal fluorine content. The Applicant provided coal fluorine content in Table A-2 (Page A-8) of Exhibit A to the permit application.

Commenters argue that data provided by the USGS COALQUAL database should not be used. Again, Commenters’ claim rests on the incorrect assumption that it is possible for a facility like Plant Washington to know the precise fluorine content of the coal it will burn when the facility has not been built or even permitted. The developers simply cannot know this specific information at this stage of the project’s development. To account for this uncertainty, the Applicant derived a predicted coal fluorine content from the most comprehensive database of coal quality that exists: COALQUAL. The COALQUAL data is representative of the coal Plant Washington is likely to burn, and that conclusion is supported by

the fact that the design coal fluorine content data provided in Table A-2 of the permit application (based on COALQUAL data) is consistent with coal analyses for various PRB coal mines (including data provided in Commenters' Ex. 19). Commenters' criticism of the Applicant's reliance on COALQUAL data should therefore be disregarded. Commenters likewise lack any basis to suggest that COALQUAL data is not sufficiently specific for purposes of the federal regulations governing Case-by-Case MACT applications. No such requirement exists in 40 C.F.R. § 63.43(e)(2)(viii), which provided as follows:

(viii) The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source, to the extent this information is needed by the permitting authority to determine MACT.

Data was provided in the Plant Washington permit application regarding uncontrolled emission rates. These rates were based on expected concentrations in the coal based on best available analytical data, the expected source of the coal, and the expected maximum firing rate of the main boiler. This data was reported at the accuracy level needed by the permitting agency to determine MACT.

Comment: The MACT limits are less stringent than other HF emission limits for coal fired electric utility boilers. Emission limits for sources including the Longview facility in West Virginia and the Thoroughbred facility in Kentucky are lower than those proposed for Plant Washington. (Ex. 53, Ex. 62)

Response: The Applicant has reviewed the references by Commenters regarding this issue. The permit for the Longview facility in West Virginia (Commenters' Ex. 53) includes a 6114 MMBtu/hr utility boiler. The HF emission limits listed in Ex. 53 indicated are 2.14×10^{-3} lb/hr and 1.00×10^{-5} lb/MMBtu. It was noted that the permit limits for HF are also the same for HCl. The Applicant also reviewed information concerning the Longview facility in EPA's RBLC. The listed permit data for the site within the RBLC (March 2, 2004) corresponds with the permit data for Commenters' Ex. 53. However, the RBLC identifies the main boiler HF limit as 0.0021 lb/MMBtu. The permit engineer at the West Virginia DEP responsible for the Longview site was contacted in order to determine the accurate HF emission limit for the main boiler. The permit engineer did indicate that the values within the permit were correct. However, he indicated that he was not sure how the values for HF were derived and they were possibly part of a settlement agreement regarding the permit. Upon further review of the permit it was noted that the permit contained synthetic minor conditions to avoid major source status for HAPs. Therefore, the emission limits derived for HF and HCl were likely limits derived to maintain minor source status for HAPs, and were not derived as MACT limits. Also, please note that Commenters indicate that Plant Washington also identified another site (Maidsville) that had a lower HF emission limit than

proposed. This site (Maidsville) is the same Longview facility referenced by Commenters.

Commenters also reference the Thoroughbred plant in Kentucky, which has an HF emission limit of 0.000159 lb/MMBtu (Ex 62). This limit was discussed in Section 4.4.5 of the Plant Washington permit application. It is important to note for the Thoroughbred plant site the emission limit is identified as 0.000159 lb/MMBtu on a 30-day rolling average. The Plant Washington draft permit limit for HF is 2.17×10^{-4} lb/MMBtu on a 3-hr average. The Thoroughbred permit includes a requirement to establish a correlation between SO₂, coal quality, and HF emissions to demonstrate ongoing compliance through SO₂ CEMS. Finally, it is worth noting that the developer of the Thoroughbred facility has abandoned its plans for construction, thus preventing the Applicant from ever learning whether this Thoroughbred limit is achievable in practice.

Comment: The proposed HF limit fails to be at least as stringent as the emission controls achieved by the best controlled similar source. Permit limits often overestimate actual emissions. Stack test data demonstrates that lower emission limits are achievable. (Ex. 28, Ex. 32, Ex. 58, Ex. 59, Ex. 63, Ex. 65, Ex. 72)

Response: Commenters provide numerous references that allegedly support their claim that the HF emission limit should be more stringent for Plant Washington. These references, however, lack detailed information regarding the types of coals, or fluorine coal contents, of the coals used in the referenced tests. Without such data, a detailed evaluation of the provided data is not possible.

Also, Commenters provide data indicated as being from reference Ex. 28. However, the referenced table could not be located within the provided reference (Table 2-6.2). Instead, Table ES-1 of the provided reference included data as provided by Commenters for the Springerville and Yates sites, while no data for the Shawnee, Burger, or Nelson Dewey sites were included within the referenced document. Therefore, the validity of the data provided by Commenters cannot be confirmed.

Comment: EPD failed to fully evaluate beyond the floor HF control technologies for Plant Washington. Higher HF control efficiencies with the wet scrubber should have been evaluated. Alstom submitted data to Duke Energy indicating that 99.7-99.9% removal efficiencies have been achieved. (Ex. 55, Ex. 56)

Response: Commenters indicate that the proposed limits for HF for Plant Washington reflect 98.5% control. That is not the case. If one compares the estimated uncontrolled HF emission rate from pages A-36 and A-40 of the Plant Washington permit application (April 16, 2009 supplemental data) with the Draft Permit limit of 2.17×10^{-4} lb/MMBtu, it is clear that Plant Washington will need to achieve a removal

efficiency of greater than 99% to meet its permit limit. For this reason, Commenters' claim that EPD's beyond the floor analysis failed to evaluate (or require) the highest achievable HF control efficiencies is not supported by the permitting record.

VII. Responding to Comments Concerning Mercury Limit (Greenlaw Comment Letter Section III.D.3.c, pages 105-120).

Comment: The company proposed a mercury emission limit of 15×10^{-6} lb/MW-hr (1.68×10^{-6} lb/MMBtu) that would only apply when burning subbituminous coal. It appears that the company has proposed no mercury emission limit when burning bituminous coal or burning a blend of bituminous and sub-bituminous coal.

Response: The issue of proposing a single limit for mercury was discussed and evaluated in detail in the MACT analysis in Section 10.4.1 of the Plant Washington air permit application. The conclusions of this section read as follows:

It is unknown whether the intrinsic properties of bituminous coals that allow for higher mercury removal would be effective in improving mercury removal over use of sub-bituminous coal alone. Several DOE/NETL case studies indicate that blending bituminous coals with PRB did not improve the mercury removal efficiency, and the overall efficiency is not linear with the blend proportions. Therefore, Plant Washington is proposing a singular limit for mercury equivalent to the use of 100% sub-bituminous coals (e.g. PRB coal).

No mercury emission limit was proposed for burning bituminous coal since the plant will be designed to burn sub-bituminous coal (PRB) or up to a 50/50 blend (by weight) of eastern bituminous coal (Illinois #6) and sub-bituminous coal. The facility will not be capable of solely burning bituminous coal.

Comment: Power4Georgians appears to claim that its planned controls of a selective catalytic reduction ("SCR") system, baghouse, and wet scrubber constitute the "best demonstrated technology" for mercury based on EPA's position of its unlawful CAMR regulations. Why this is at all relevant to a case-by-case MACT determination is entirely unclear.

Response: The relevance of EPA's research and development of MACT standards for electric utility steam generating units cannot be disputed. Although CAMR may have been invalidated by the D.C. Circuit Court of Appeals, the Court's ruling was based on a procedural flaw in EPA's rulemaking. The Court's decision did not overturn the years of research and data upon which the substantive components of CAMR were based. Accordingly, Commenters' suggestion that the research and data upon which numerous EPA proposals were based — including EPA's *Regulatory Finding on Emissions of HAPs from Electric Utility*

Steam Generating Units (2000) and Proposed NESHAP, and in the Alternative, Proposed NSPS for New and Existing Electric Utility Steam Generating Units (2004) — do not provide a valid point of reference for case-by-case MACT analyses has no merit. As discussed in great detail on pages 10 through 25 of the MACT section of the permit application, these documents incorporate years of study by EPA regarding evaluation of HAP emissions from electric utilities, and development of standards for HAP emissions from electric utilities. Such research and documentation is clearly relevant to review and discuss when conducting a Case-by-Case MACT evaluation.

Comment: EPD, in its review of the Plant Washington MACT application, added three additional mercury stack test results, two of which were much lower than the 15×10^{-6} lb/MW-hr mercury MACT limit proposed by Plant Washington and are even much lower than EPD's proposed 13×10^{-6} lb/MW-hr limit. Specifically, according to EPD's notice of MACT approval, the Weston 4 unit achieved a mercury emission rate of 1.4 lb/TBtu or 8.79×10^{-6} lb/MW-hr and the Newmont Nevada unit achieved less than 7.6×10^{-6} lb/MW-hr.

Response: Commenters' reference to the Newmont and Weston 4 stack test results implies that the existence of these single stack tests somehow invalidates the mercury limit in the Draft Permit. It does not. As has been explained repeatedly throughout the MACT analysis, several short-term stack tests alone cannot establish what emission rate can be achieved in practice. That is especially true for mercury emissions at Plant Washington, which will be measured continuously through use of a mercury CEMS device. This system will continuously measure emissions during transient conditions (e.g. load condition changes). Also, periods of inefficiency in the facility's operations could increase the lb/MW-hr equivalent emissions, since emissions will be based on the gross power output of the system and not the heat capacity input of the main boiler. For these reasons, Commenters' suggestion that a few one-time stack tests demonstrate what long-term emission limits will be achievable at Plant Washington over the life of the facility is inaccurate.

Moreover, Commenters fail to mention that along with the Weston 4 and Newmont data, EPD identified a third mercury stack test for the Tuscon Electric Springerville Unit 3 site. Springerville Unit 3 had a tested result of 2.27×10^{-6} lb/MMBtu, equivalent to 21.7×10^{-6} lb/MW-hr and thus well in excess of the limit that EPD set for Plant Washington in the Draft Permit.

Comment: Neither the company nor EPD have disclosed the design basis of the Plant Washington boiler, including specific information necessary to determine the uncontrolled levels of mercury expected from Plant Washington. While the company provided coal mercury data for subbituminous and bituminous coals

from the USGS CoalQual database, that database is overly broad and does not reflect the specific coals currently proposed to be burned at Plant Washington.

Response: Page A-8, Table A-2 of the Plant Washington permit application lists the mercury coal design data for Plant Washington. Uncontrolled facility mercury emissions, based on the coal design data, were estimated on Page A-37 of the permit application. Therefore, Commenters have no basis to claim that the design basis of the coal to be fired at Plant Washington was not indicated in the permit application.

Commenters indicate that data from the USGS COALQUAL database does not reflect the coals to be burned at Plant Washington. However, a review of data provided by Commenters (Ex. 19) for PRB coal, as well as a additional data reviewed by the Applicant, indicated that the mercury content data indicated for PRB coal from the COALQUAL database is consistent with analysis data provided by Commenters for various PRB coal mines. The COALQUAL database included over 1,000 samples of coal from Wyoming and Montana that were analyzed for mercury. Discussions with USGS personnel during the permitting process indicated that reported results within the COALQUAL database were not based on a “dry” basis due to the sample handling procedures used prior to analysis. Consultation with the USGS indicated the proper procedures to use to correct for the residual moisture contained within the analyzed samples. These corrections were discussed in Section 10 (Page 10-10) of the Plant Washington permit application.

Comment: *EPD must also obtain specific design thermal efficiency data for Plant Washington’s boiler, if EPD is going to set limits in terms of lb/MW-hr that truly reflect MACT for Plant Washington.*

Response: The efficiency of a power generation facility like Plant Washington is typically demonstrated in terms of its heat rate. Heat rate is the measure of heat input required to produce a given output in terms of Btu/kWhr. For Plant Washington, the full load gross heat rate is approximately 8925 Btu/kWhr, determined from the maximum heat input rate of the main boiler (8300 MMBtu/hr) and the gross output of the unit at full load (930 MW or 930,000 kW). As boiler load decreases, the unit will operate less efficiently and the gross plant heat rate will increase. Thermal efficiency, as mathematically defined, is the ratio of boiler output to boiler input, which is the portion of the energy generated that makes it into the heating medium (e.g. water). Thermal efficiency is typically defined at steady state and the full firing rate of the boiler. Therefore, thermal efficiency only addresses a portion of the overall system efficiency of a utility boiler, since it does not account for the efficiency of the facility power generation systems (e.g. turbine).

The Plant Washington system thermal efficiency, and overall system efficiency, will vary with varying load conditions. As indicated above, the estimated full load gross heat rate of the system is 8925 Btu/kWhr. Plant Washington will utilize a supercritical boiler system that will provide the optimum boiler operating efficiency for that type of system.

Comment: The same degree of mercury reduction can now be achieved from coals, regardless of rank, using advances in mercury control technology that have occurred since the research studies relied on in the 2005 proposed rulemaking. Exs. 82-85. These advances and experiences have allowed for comparable mercury reductions across all boiler and coal types. (Ex. 82, Ex. 83, Ex. 84, Ex. 85)

Response: The Applicant has reviewed the Commenters' references concerning the effect of coal type on mercury emissions. These references contain DOE/NETL mercury test program information for various sites. Documentation regarding DOE/NETL testing was discussed at length in Section 10.4.1.4 of the Plant Washington air permit application. Commenters' Exs. 82 and 83 discuss studies of sites utilizing PRB control with mercury control ranging from 67-90%, and sites utilizing bituminous coals with mercury control efficiencies from 31-90%. While high removal efficiencies were achieved for different coal types, the results of these studies demonstrate that comparative results between facilities can be highly variable. Accordingly, the Applicant does not agree with Commenters' claim that the DOE/NETL data indicate that the same degree of mercury reduction can be achieved regardless of coal type.

Comment: In fact, research suggests that it is more difficult to remove mercury from high chlorine bituminous coals, due to sulfuric acid mist. Additional controls, e.g., trona injection, not considered by EPD, may be required to meet BACT if Plant Washington fires such coals. (Ex. 88A, Ex. 88B)

Response: As Plant Washington's design coal data (Page A-8, Table A-2) clearly indicates, Plant Washington will be utilizing high chlorine bituminous coals. Use of sorbent injection for control of sulfuric acid mist emissions (including the use of Trona) was discussed in the BACT analysis in Section 4.3.7 of the permit application. Plant Washington will utilize sorbent injection for the control of sulfuric acid mist. Therefore, statements made by Commenters on this issue are not relevant, as Plant Washington will be effectively controlling sulfuric acid mist emissions.

Comment: Mercury can now be controlled to the same degree of reduction when firing any coal type due to commercially available products. First, the chlorine content of low chlorine sub-bituminous coals can be boosted by blending in 15 to 50% bituminous coal or by adding proprietary chemicals. Given that Plant

Washington may be blending up to 50% Illinois #6 bituminous coal with sub-bituminous coal, this may result in high levels of mercury reduction. (Ex. 82, Ex. 83, Ex. 85, Ex. 86, Ex. 89, Ex. 90, Ex. 91)

Response: This issue, as discussed previously, was addressed in the Plant Washington permit application. Although Commenters provide some references of DOE/NETL study data which show improvement in mercury removal when blending bituminous and sub-bituminous coals, extensive DOE/NETL test results and studies reviewed and discussed in Section 10.4.1 of the Plant Washington permit application indicated no improvement in the mercury removal efficiency when blending bituminous and sub-bituminous coals. Variable results were also seen from these studies when adding proprietary chemicals. For these reasons, which are set forth in much greater detail in the permit application, Commenters' claims regarding the alleged benefits of blending coals or the use of proprietary chemicals for mercury reduction are not supported by the Applicant's review of available data.

Comment: *EPD's proposed mercury MACT limit for Plant Washington of 13×10^{-6} lb/MW-hr equates to approximately 1.46 lb/TBtu. Lower mercury emission limits have been achieved in practice at numerous units. Several units in EPA's 1999 Information Collection Request (ICR) testing had mercury emission rates lower than 1.46 lb/TBtu, and none of those units had mercury specific controls. (Ex. 29)*

Response: EPA's 1999 Information Collection Request (ICR) data was reviewed and discussed on Page 10-18 of the permit application's Case-By-Case MACT analysis. The reference provided by Commenters (Ex. 29) is a summary of ICR testing results for 80 facilities. Commenters fail to point out that the results they list in Ex. 29 only include 21 of 80 total sites evaluated in the ICR, nor do Commenters acknowledge that the results of the 59 other sites recorded mercury emission rates greater than or equal to the 1.46 lb/TBtu limit EPD has proposed for Plant Washington. Also, only 5 of the sites listed by Commenters used sub-bituminous coal (4 sites) or a blend of bituminous and sub-bituminous coals (1 site) during testing. The other listed sites used either waste coal, bituminous coal, or a blend of bituminous coal and petcoke during emissions testing evaluations. When evaluating only those sites utilizing sub-bituminous coals, or a blend of bituminous and sub-bituminous coals, values ranged from 0.4606 lb/TBtu to 10.6 lb/TBtu, with an average value of 4.77 lb/TBtu for the 32 sites evaluated.

Comment: *Another example of a unit meeting a lower mercury emission rate is Reliant Energy's Seward Station. The units at this facility achieved mercury emission rates ranging from 0.01 – 0.02 lb/TBtu which, according to the test report, reflects 100% mercury removal. These units (CFB boilers) were burning waste bituminous coal with a mercury content ranging from 0.276 – 0.465 parts per million. (Ex. 127)*

Response: Commenters contend that emission rates of mercury should be evaluated regardless of coal rank. However, as discussed on Page 10-26 of the Case-by-Case MACT analysis, coal waste material is a significantly different fuel source than standard coal. The following is an excerpt from Page 10-26 of the permit application:

Utilizing coal refuse, or waste coal, can result in low mercury emissions. Statements made by the EPA in the January 2004 proposed MACT standard for utility boilers indicated "Available data indicate that emissions from the combustion of coal refuse tends to result almost entirely in particulate bound Hg (greater than 99 percent for both units tested in the 1999 EPA ICR)." Therefore, with such a high percentage of mercury present in the particulate phase in coal refuse, significant removal efficiencies (i.e. 98%+) are possible for total mercury when combusting waste coal.

Waste coal was evaluated as a separate coal rank in the development of the NSPS standards for mercury (Subpart Da), the Clean Air Mercury Rule (CAMR), and the draft MACT standards for utility boilers. These characteristics of coal refuse allow for much lower mercury limits for units combusting coal refuse. A recent MACT analysis for a Dominion Circulating Fluidized Bed (CFB) boiler indicated a mercury limit of 49 lb/yr, based on a removal efficiency of 98% for total mercury. This limit was based on the use of waste coal at the facility. CFB units are capable of combustion of waste coal, where standard pulverized coal-fired boilers are not due to the high level of impurities present in the waste coal.

Since the units referenced by the Commenters utilize a fuel type that could not be used in the Plant Washington main boiler, a comparison of testing results from such a unit is not a valid basis of comparison.

Comment: *Another example of a unit meeting a lower mercury emission rate is the Midamerican Walter Scott Jr. Unit. This unit attained a mercury emission rate lower than 0.72×10^{-6} lb/MMBtu during the May 2007 test (see Ex. 70). Further, the Santee Cooper Cross Unit 3 was shown in testing to emit mercury at a rate of 0.72 lb/TBtu and 0.58 lb/TBtu. (Ex. 70, Ex. 73, Ex. 74)*

Response: Commenters' Ex. 70 is the same stack test report discussed on Page 10-21 of the Plant Washington permit application for the Midamerican site (an August 2007 test), and that test report reflects an emission rate of 1.2×10^{-6} lb/MMBtu, not 0.72×10^{-6} lb/MMBtu. Thus, the two stack tests for Midamerican show significant variability. Commenters' Exs. 73 and 74 were also reviewed, and the referenced emission rate of mercury of 0.58 lb/TBtu could not be located. Commenters' Ex. 75, which sets forth stack test data for Santee Cooper Cross Unit 4 (an identical unit to Unit 3), reported a mercury emission rate of 1.74

lb/TBtu, a value that exceeds the 1.46 lb/TBtu limit EPD has proposed for Plant Washington.

Comment: Units that burn pet coke or a blend of pet coke and coal have also been shown to achieve lower mercury emission rates than EPD's proposed MACT limit for Plant Washington. JEA Northside includes two CFB boilers equipped with spray dryer absorbers and baghouses that burn pet coke and/or coal. These units achieved a mercury emission rate of 0.51 lb/TBtu while burning 70% pet coke and 30% Pittsburg No. 8 coal, 0.28 lb/Tbtu while burning 100% pet coke, and 0.074 lb/TBtu while burning 80% pet coke and 20% Pittsburg No. 8 coal. (Ex. 32, Ex. 33, Ex 34)

Response: The Applicant has reviewed Commenters' Exs. 32, 33, and 34. Initially, while the Applicant was able to locate test results for the 80% pet coke and 20% Pittsburg No. 8 fuel blend referenced by Commenters in Ex. 32, the other referenced test results could not be located within the references provided. Additionally, Commenters fail to note that their Ex. 32 describes how burning 100% petcoke produced technical problems. Specifically, page 20 of Ex. 32 states as follows:

Initial operation of the boiler on coal and higher ratios of coal/pet coke blends were successful. However, attempts at operation on 100% pet coke resulted in agglomeration of ash in the INTREX's and cyclones within a week or so of operation, requiring a forced outage to remove the ash build-up. As a result, blending of pet coke and coal was required for reliable operation of the boiler.

References provided by Commenters were from 2004 and 2005. It is unknown if there were other tests conducted prior to or following this time that were not reported. Tested results for the 100% Pittsburgh #8 coal were 7.238 lb/TBtu, at only a 14% mercury control efficiency (Commenters' Ex. 32), while the mercury emission rate for the 80% pet coke and 20% Pittsburg #8 coal blend was 0.074 lb/MMBtu at 98% total mercury removal efficiency. It is unclear if the improved efficiency and achieved emission limit was due to fuel blending with petcoke since results for a 50/50 blend of pet coke and Pittsburg #8 coal (Ex. 32) were simply reported a mercury emission rate of < 8.532 lb/TBtu, with no removal efficiency determined due to testing complications.

Comment: Yet another example is the Hardin Generating Station. This facility burns Powder River Basin sub-bituminous coal, and is equipped with an SCR, dry scrubber, fabric filter, and ACI system. A presentation on the mercury reductions achieved at Hardin provides a graphical representation of 10 months worth of mercury emissions. Specifically the 17th slide of the attached presentation shows that, over the 10 month period from September 2007 to July 2008, mercury emissions from Hardin rarely ever exceed 0.5 µg/m³ and are often much lower than 0.5 µg/m³. (Ex. 93)

Response: Commenters fail to accurately describe the contents of slide 17 of Commenters' Ex. 93. While the title for the slide indicates *Long-Term Test: Sept '07 – July '08*, the dates on the referenced graph indicate that the graphs are representative of data for a 13-day period, 9/26/07 to 10/8/07. The limited scope of the data on slide 17 is confirmed by reviewing slide 13 of Ex. 93, which reports emission rates for the dates 10/1/07 to 10/8/07 that corresponds with the data presented for those dates on slide 17. In sum, the data on slide 17 are not representative of long-term operation, as Commenters claim. Also, Commenters indicate that the value of $0.5 \mu\text{g}/\text{m}^3$ corresponds to an emission rate of $0.305 \times 10^{-6} \text{ lb}/\text{MMBtu}$. It is unclear how this value was derived without specific information (e.g. heat input to the tested boiler).

Comment: *At least 2 permits have been issued with lower mercury MACT limits. Utah issued a permit in October 2004 for the NEVCO Energy-Sevier project, a 270 MW CFB unit that will burn bituminous coal with a mercury MACT limit of 0.4 lb/TBtu. Virginia issued a permit in July 2008 to Virginia Electric and Power Company for two CFB boilers with a combined output of 668 MW. The boilers would burn bituminous coal and waste coal and have a mercury MACT limit of $0.88 \times 10^{-6} \text{ lb}/\text{MW}\text{-hr}$. (Ex. 111, Ex. 112)*

Response: While the NEVCO Energy-Sevier project does have a mercury limit of 0.4 lb/TBtu, compliance with this limit is to be demonstrated by a short-term initial compliance test. Continued long-term compliance with the permit limit is determined through permit Condition 19 (Commenters' Ex. 111), which reads as follows:

The mercury content of any coal burned in any fuel burning process shall be monitored and recorded for each load of fuel delivered. Certification of fuels shall be either by Sevier Power Company's own testing or test reports from the fuel marketer. For determining mercury content in coal, American Society for Testing and Materials (ASTM) Method D3684-01 or other method approved by the Executive Secretary, is to be used.

If the initial emission testing for mercury is passed, the source can operate using coal with mercury content no greater than 110% of the tested mercury content without further emission testing. Coal with higher mercury content shall not be used until successful testing at this value has been completed. A new mercury content value of 110% of this tested value shall then be allowed without further emission testing.

As this provision demonstrates, continuous compliance for this facility will not be demonstrated through a CEMS device like Plant Washington, but by monitoring of the mercury concentrations of coals used at the facility. Without knowing the

expected coal mercury concentrations for this site, the Applicant cannot conduct a meaningful comparison of this facility.

The Applicant also reviewed the Virginia Electric and Power Company permit (Commenters' Ex. 112). As Commenters note, the site is permitted to burn both waste coal and bituminous coals. Commenters fail to mention the following "escape hatch" that was originally written into the Virginia Electric and Power Company's permit:

Stack Tests - There is limited experience with electric generating units operating under MACT limits for mercury. Therefore, if the permittee reasonably demonstrates using operational and other related information collected for a period not shorter than the first 12 months of operation of all the equipment used to control mercury (including limestone injection, fluidized gas desulfurization, activated carbon injection, fabric filters and good combustion practices) that the lb/MWhr limit is not achievable on a consistent basis under reasonably foreseeable conditions, then testing and evaluation shall be conducted to determine an appropriate adjusted maximum achievable annual emission limit in accordance with the following procedure:

Although this permit condition was later struck down by a reviewing court, it is clear evidence that the applicant and the permitting authority did not formulate the mercury emission limit in the permit with complete confidence that such a limit would be achievable. While the permit applicant ultimately agreed to forfeit this flexibility in response to the court decision, the applicant's ability to exclusively fire waste coal to meet this low limit distinguishes this facility from the operating parameters Plant Washington will face. Accordingly, the Virginia Electric and Power Company facility does not provide a valid basis of comparison to Plant Washington.

Comment: The ReACT process was demonstrated in 2007 on a 2.5 MW slip stream at the 250-MW Valmy Generating Station in Nevada on both sub-bituminous and bituminous coals. The Valmy demonstration reported SO₂ removal of 98->99%, NO_x removal of 26-48%, and mercury removals of 97->99%. ReACT has been installed on 14 commercial units to date, including 4 coal fired utility boilers in Japan and Europe. (Ex. 51A, Ex. 51B, Ex. 75)

Response: In Commenters' view, 99% mercury removal is achievable (and thus should have been considered in the beyond-the-floor analysis) through use of the ReACT process. Commenters suggest that Ex. 75 contains information regarding ReACT installations in Japan and Europe. However, Ex. 75 is a test report for Santee Cooper Cross Unit 4. Data regarding Isogo Unit 1 was located within Ex. 51B. The Applicant was unable to find any data regarding the Isogo Unit 1 mercury removal performance except for that data presented in Commenters' Ex. 51B. This exhibit, however, does not indicate how the Isogo Unit 1 performance was

determined (i.e., long-term vs. short-term performance, stack test vs. CEMS). Thus, the Applicant cannot draw any meaningful conclusions from this information.

What is important to consider is that the quoted information regarding mercury removal for the Valmy Generating Station was from a 2.5 MW slipstream demonstration unit (approximately 1% of the system airflow) and was not from a full-scale demonstration unit.

Comment: *The Holcomb Unit 1 power plant, which burns PRB sub-bituminous coal, achieved 93% mercury control in long term testing. Over a year of continuous mercury CEMS data is available for the WE Energies Presque Isle facility in Michigan, which burns sub-bituminous coal, and these data demonstrate that over 90% mercury control has been achieved on a continuous basis. At least two other full-scale long term mercury control demonstrations have been reported to achieve 90%+ mercury control – at Rocky Mountain Power (Hardin) in Montana, and at Comanche Station in Colorado. (Ex. 85, Ex. 93, Ex. 100, Ex. 101, Ex. 102, Ex. 103, Ex. 104, Ex. 105)*

Response: Commenters' Ex. 85, involving the Holcomb Unit 1 site, was reviewed. Commenters suggest that 93% mercury control was achieved in long-term testing at Holcomb Unit 1. Based on documentation provided in Commenters' Ex. 85, however, the duration of the test was 30 days, during which the average mercury removal was 91%. The system achieved an average removal of 93% during days 6 through 30 of testing. Commenters cannot claim that these results constitute "long-term testing."

Information regarding the Hardin Generating Station (Commenters' Ex. 93) was discussed in response to another comment. As was previously noted, the data reported in this document only represents a period of 13 days, and thus is not an example of long-term testing. Data referenced regarding the Comanche Station could not be reviewed since Ex. 105 was not included in the references provided by Commenters.

Data for the Presque Isle facility was evaluated, and that data does indicate that a 90% mercury removal was achieved for this unit on a long-term basis. Slide 11 of Ex. 102 displays the daily average mercury removal for 2007 with a note indicating the overall average for the period was 90%. However, what is apparent from this graph is that there are many days when the average removal efficiency is less than 90%, and the system performance regarding mercury removal is highly variable on a day-to-day basis, with the exception of a period between March and April 2007. This variability indicates that there are many potential forces at work that can affect mercury removal at this facility, including the amount of activated carbon injected, chlorine content of the coal, mercury content of the coal, effectiveness of the control devices, and variability in the mercury

CEMS device. It is difficult from this data to isolate a single cause for the variability, and as a result, the Applicant cannot conclude that these results can necessarily be replicated at Plant Washington.

In sum, as discussed on Page 10-37 of the Plant Washington permit application, although studies have suggested that removal efficiencies of 90% or greater for total mercury has been obtained in certain stack tests when utilizing PRB coals, the emission controls in use at the majority of facilities evaluated did not include the full range of control technologies that will be in use at Plant Washington.

VIII. Responding to Comments Concerning Testing and Monitoring Requirements for HAPs (Greenlaw Comment Letter Section III.D.3.e, pages 121-125).

Comment: The Permit fails to include any testing or monitoring, recordkeeping or reporting requirements for mercury during the first year of operation of Plant Washington.

Response: Commenters have no basis to suggest that Plant Washington will not be testing, monitoring and recording mercury emissions during the first year of operation. In order to comply with a rolling 12-month average, Plant Washington will be required to collect data every day of operation. All the data that the facility will collect regarding its mercury emissions will be available for inspection by EPD at any time during the first year of operation.

Comment: The Permit requires a single stack test for HF and HCl (for each coal type) over the entire life of the Facility.

Response: Commenters misconstrue the permitting process in the State of Georgia as it pertains to monitoring and reporting requirements. The federal Clean Air Act and Georgia law require Plant Washington to submit an application for a Title V operating permit within one year after the facility commences operation. The Title V permitting process will allow EPD to review the results of initial performance tests and coal data at Plant Washington and impose additional testing, reporting, and monitoring requirements in the event such requirements are necessary to ensure compliance with the permit limits. Commenters therefore are incorrect to suggest that the PSD permit at issue determines the frequency of stack testing for HF and HCl “over the entire life of the Facility.”

Comment: The Permit does not define adequate testing or monitoring, excess emissions, exceedances, or excursion reports for HCl and HF (Condition 7.25). The permit does not require that SO₂ CEMS and pH data be used to determine compliance with the HCl and HF limits. The SO₂ CEMS does not assure compliance with the HCl and HF emission limits. By way of example, if SO₂ is used to determine

continuous compliance with HCl and HF, at the very least, the permit should clearly state that an SO₂ violation equals an HCl and HF limit violation.

Response: Commenters' criticisms of the testing, monitoring, and compliance provisions for HCl and HF are not valid. The relevant language in the Draft Permit is at Condition 7.25(c), which reads as follows;

c. Excursions: (means for the purpose of this Condition and Condition No. 7.25, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring).

i. Anytime the pH of the scrubbant of the Wet Limestone Scrubber is below the minimum pH determined during the test required by Condition 6.9.

ii. Any exceedance of the SO₂ emission limit in Condition 2.13 is an excursion for HF and HCl.

iii. Anytime the H₂SO₄ sorbent injection rate is below the minimum rate determined during the test required by Condition 6.10.

Contrary to Commenters' claim, the Draft Permit does clearly provide that an exceedance of the SO₂ emission limit is an excursion for HF and HCl.

Commenters also contend that there is no relationship between chlorine, fluorine, and sulfur in coal, and that monitoring of SO₂ does not assure compliance with the HCl and HF emission limits. These claims statements are in direct conflict with other statements made by Commenters regarding the acid gases HF and HCl. On page 98 of Commenter's response document, Commenters note that:

SO₂, HCl, and HF are acid gases that are removed by similar chemical and physical mechanisms. Both HCl and HF are stronger acids and are thus more reactive than SO₂ in scrubber systems. This would typically produce higher removal efficiencies for HCl and HF than for SO₂, all other parameters being equal.

As Commenters recognize, HCl and HF are acid gases that will be effectively controlled by the wet scrubber system at Plant Washington. Therefore, effective control of SO₂ will ensure effective control of HCl and HF. Monitoring the efficiency of the wet scrubber provides a direct measurement of scrubber performance. These statements are in direct agreement with statements made by Commenters.

Comment: *There is typically no correlation between sulfur in coal (and hence SO₂ in stack gases) and chlorine or fluorine in the coal (and hence HCl and HF in the stack*

gases). For example, the chlorine in the coal could triple while the sulfur content remains constant. This could lead to an exceedance of the HCl limit, but no change in SO₂ emissions. Thus, the SO₂ CEMS does not assure compliance with the HCl and HF emission limits. (Ex. 19, Ex. 20A-C)

Response: Commenters provide some data (Ex. 20A-C) that they suggest support their claims that there is no relationship between sulfur content and concentrations of fluorine and chlorine in the coal. The data in Ex. 20A-C, however, was a limited data set which did not contain any statistical correlation analyses between the sulfur content and content of chlorine and fluorine in the coal. Therefore, no direct conclusions can be drawn from this data regarding a relationship between sulfur content and fluorine and chlorine content in the coal.

Comment: *Continuous Emission Monitoring Systems (CEMS) are available for both HCl and HF and are widely used in other industries. While they have not been used on coal-fired power plants in the United States to our knowledge, HCl and HF CEMS are capable of being used on these units. On April 22, 2009 EPA recommended that North Carolina require a HCl CEMS to assure that HCl emissions at Cliffside Unit 6 remain below the MACT applicability threshold. In addition, Florida recently issued a revised draft permit for the Seminole plant that requires use of HCl and HF CEMS. (Ex. 115, Ex. 116, Ex. 117)*

Response: Commenters themselves indicate that, to their own knowledge, HF and HCl CEMS have not been used on coal-fired power plants in the United States. A significant concern regarding their use in these systems is the level of detection of the CEMS devices. A June 2009 response written by the North Carolina Department of Environment and Natural Resources to the EPA regarding use of HCl CEMS discussed those issues:

One of the concerns associated with using continuous HCl monitoring is the low HCl concentration expected in the exhaust of Cliffside Unit 6. The expected HCl concentrations are lower than the EPA's performance specifications for allowable drift, making it highly unlikely that such a monitor would provide accurate or meaningful data.

With the low concentrations of the acid gases HCl and HF expected in the exhaust gas stream at Plant Washington, the ability of CEMS devices to accurately monitor HF and HCl has not been proven. The expected concentration of HCl in the flue gas stream is approximately 0.24 ppm, and the expected concentration of HF in the flue gas stream is 0.3 ppm. Review of minimum detection limits for HCl CEMS devices indicated detection limit values of 0.1 to 0.18 ppm, and minimum detection limits for HF of 0.1 to 0.22 ppm. Documentation for one CEMS device cautioned that the actual detection limit would vary depending on the source specific conditions of the stack in question. On account of the low expected concentration of HCl and HF in the flue gas stream and the expected

drift of the CEMS instrument based on vendor data (4-5%), meaningful data collection on a utility boiler stack would be difficult as the drift of the instrument could be more than twice the expected concentration of HF or HCl in the flue gas. As discussed by NC DENR in their response to comments made by the EPA, it is expected that a CEMS device for monitoring HCl and HF on a utility boiler stack would not provide meaningful data.