

**CASE-BY-CASE MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY  
ASSESSMENT FOR HAZARDOUS AIR POLLUTANTS**

**Unit No. 6  
CLIFFSIDE STEAM STATION PROJECT**

**Executive Summary**

At the request of the North Carolina Department of Environment and Natural Resources, Duke Energy Carolinas, LLC is providing this maximum achievable control technology assessment for hazardous air pollutant emissions from the Cliffside Steam Station Unit 6, which is currently under construction. This assessment provides: (1) a plant description; (2) regulatory background on application of maximum achievable control technology to electric generating units under §112(g) of the Clean Air Act; (3) a discussion of practical factors to be accounted for in determining the appropriate limit; (4) a list of the hazardous air pollutants to be considered; and (5) an assessment of MACT-equivalent emission limitations under the §112(g) criteria. The assessment concludes that the following would be MACT-equivalent emission limits for Cliffside Steam Station 6:

<b>HAP</b>	<b>Control Technology Employed by Best Controlled Similar Source Demonstrated in Practice</b>	<b>Control Technology Employed by CSS6</b>	<b>MACT-Equivalent Emission Limit</b>	<b>Performance Indicator (or surrogate)</b>
<b>Hg</b>	SCR, SDA, FF	SCR, SDA, FF, wet FGD	0.014 lb/gross GWH, 12-month rolling average	Hg CEM
<b>HCl</b>	SDA / FF	SDA / FF, wet FGD	Existing SO <sub>2</sub> limit of 0.12 lb/MMBtu, 30-day average	SO <sub>2</sub> CEM
<b>HF</b>	SDA / FF	SDA / FF, wet FGD	Existing SO <sub>2</sub> limit of 0.12 lb/MMBtu, 30-day average	SO <sub>2</sub> CEM
<b>HAP Metals</b>	FF	FF	Existing PM limit of 0.012 lb/MMBtu	Stack Test for Filterable PM
<b>Organic HAPs</b>	Combustion Control	Combustion Control	CO limit of 0.10 lb/MMBtu	Stack Test for CO

## Assessment

This Case-by-Case Maximum Achievable Control Technology (“MACT”) Assessment provides (1) background information on the Cliffside Modernization Project and its regulatory status, and (2) a MACT Assessment for mercury (“Hg”), non-mercury metals or “particulate” Hazardous Air Pollutants (“HAPs”), acid gas HAPs and organic HAPs as requested by the North Carolina Department of Environment and Natural Resources (“DENR”) Division of Air Quality.<sup>1</sup>

### 1. Plant Description

Duke Energy Carolinas, LLC (“Duke”) is presently constructing Cliffside Steam Station Unit 6 (“CSS6”), a supercritical, pulverized coal-fired boiler with a nominal heat input rating of 7850 MMBTU/hr. It is located on the Cleveland/Rutherford County line in North Carolina. The Prevention of Significant Deterioration (“PSD”) Permit (the “Permit”) authorizing CSS6’s construction was issued on January 29, 2008, and actual physical construction began on January 30, 2008. At that time Duke also committed to purchasing the major plant components.

CSS6 will employ a supercritical boiler designed to combust a variety of eastern bituminous coals including a blend of eastern bituminous and not more than 50 percent sub-bituminous coals. This design ensures an efficient production of power and contributes to minimizing the emissions per unit of power output.

As will be detailed in the following sections, the CCS6 project includes an unprecedented, state-of-the-art system of control technologies and practices to minimize air emissions: low NO<sub>x</sub> burners and Selective Catalytic Reduction (“SCR”) for NO<sub>x</sub> control; and an innovative combination of a spray dryer absorber, fabric filter, and wet Flue Gas Desulfurization (“FGD”) for the control of SO<sub>2</sub>, SO<sub>3</sub> and other

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<sup>1</sup> While this Assessment is not required by § 112 of the Clean Air Act, it is being submitted to determine levels of control for HAPs that is intended to be functionally modeled on the § 112 process as a “MACT-like” process, which Duke Energy Carolinas, LLC has agreed to undertake at the request of DENR. References in this document to “MACT” or “MACT requirements” or similar topics are not to be taken in contravention of this being a “MACT-like” process, rather than one required under § 112.

acid gases, and particulates, and mercury. These last three components will be designed to operate as one integrated system.

## **2. Regulatory Background**

When the Permit was issued for Cliffside and physical construction began, the Clean Air Mercury Rule (“CAMR”) was in effect. CAMR would have imposed New Source Performance Standards (“NSPS”) emission limits on CSS6 for a number of air pollutants including a limit on the allowable mercury emission rate. CAMR also allowed CSS6 to participate in a mercury cap and trade program and required continuous mercury emission monitoring. The Permit contains limits reflecting both CAMR and North Carolina Air Quality Rules (15A NCAC 02D .2511), which require the application of case-by-case Best Available Control Technology (“BACT”). Given the mercury limits under the Clean Air Interstate Rule (“CAIR”) and BACT-imposed stringent limitations on mercury emissions, the CSS6 design included state-of-the-art equipment that would stringently control those emissions.

### **a. MACT Regulation of EGUs**

Subsequent to Duke’s commencement of construction and contracting for equipment, on February 8, 2008, the United States Circuit Court of Appeals for the District of Columbia granted petitions filed by State of New Jersey, *et al.*, vacating CAMR (United States Court of Appeals for the District of Columbia Circuit, Case No. 05-1097). Subsequently the court issued its mandate. It is important to note that the Permit, which was issued before the DC Circuit’s decision, satisfies all applicable legal and regulatory requirements in force at the time it was issued, and at the time that construction commenced. However, DENR has indicated that the court’s decision vacating CAMR creates a debate about the possible application of MACT limitations for HAPs under section 112 of the Clean Air Act. See the letter from B. Keith Overcash, P.E. to Rick R. Roper dated June 2, 2008, provided in Attachment 1. Without opining on its applicability to CSS6, that letter requested that Duke submit an assessment for CSS6, consistent with the Clean Air Act § 112(g) as if it did apply:

Therefore, regardless of whether § 112(g) applies to CCS6 by its own terms, DAQ believes that the best course of action is to initiate a public process now, consistent with the standards in § 112, to determine the maximum degree of reduction in emissions of HAPs that is achievable for the category of source in which CSS6 falls, consistent with the analysis that would apply under § 112.

Duke responded to DENR in a letter dated June 13, 2008, saying that it would submit an assessment consistent with the requirements of § 112(g), but also reserving its rights and defenses concerning whether § 112(g) applies to the CSS6 project. This submittal is Duke's assessment.

**b. What 112(g) Requires.**

When applicable to a project, § 112(g) requires a case-by-case MACT for major sources of HAP emissions where EPA has not yet promulgated a MACT standard for a listed source category. EPA proposed a MACT standard for utility boilers; it did not finalize that standard and instead de-listed utility boilers as MACT source category and promulgated CAMR under CAA § 111. Section 112(g) requires the setting of emission limits on HAPs using a two-part analysis: (1) a determination of the emission limitation achieved in practice by the best controlled similar source (otherwise known as the MACT Floor); and (2) the level of additional control, if any, that can be achieved by the source taking into consideration, cost, energy requirements, and non-air quality-related health and environmental impacts. The case-by-case MACT emission limit cannot exceed the MACT Floor. As pointed out by DENR, MACT is a categorical standard that applies to all EGUs within a category, and a case-by-case MACT Assessment is intended to predict what the Agency would determine is MACT for that category when it completes that rulemaking.<sup>2</sup>

**c. Implementing rules and guidance.**

15A N.C.A.C. 2D.1112(d) provides the regulatory basis for preparing a case-by-case MACT Assessment:

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<sup>2</sup> Duke may submit a more detailed explanation of its position on the MACT requirements under separate cover at a later date.

*(d) Principles of MACT determinations. The following general principles shall be used to make a case-by-case MACT determination concerning construction or reconstruction of a major source under this Rule:*

*(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the Division shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Division.*

*(2) Based upon available information, the MACT emission limitation and control technology (including any requirements under Subparagraph (3) of this Paragraph) recommended by the applicant and approved by the Division shall achieve the maximum degree of reduction in emissions of HAP that can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.*

*(3) The owner or operator may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the Director may approve such a standard if the Division specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the federal Clean Air Act.*

*(4) If the EPA has either proposed a relevant emission standard pursuant to Section 112(d) or 112(h) of the federal Clean Air Act or adopted a presumptive MACT determination for the source category that includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.*

See also 40 C.F.R. § 63.43(d). The language in sub-section (4) above implements CAA § 112(i)(2), which says that a proposed MACT rule governs sources on which construction commences after the rule is proposed and before the final rule is promulgated. EPA proposed a MACT rule for EGUs in 2004 (69 FR 4669, January 30, 2004) and chose not to act on it when CAMR was promulgated in 2005. Although EPA did not finalize the proposed MACT rule for EGUs rule in 2005 when it promulgated CAMR, EPA's proposed rule is instructive in preparing the MACT Assessment for CSS6 and is the best evidence of EPA's thoughts on the matter.

**d. Determination of a "Similar Source"**

Step 1 of the MACT Assessment is to identify the emission limit of the best controlled similar source demonstrated in practice or the "MACT Floor." It is important to recognize that reductions in certain

pollutants can result in an increase of other pollutants, e.g., lower CO or organic HAP emissions result in higher NO<sub>x</sub> emissions. Therefore, the best controlled similar source may not have the lowest emission limit for each individual pollutant. After establishing the MACT Floor for that similar source, the assessment further examines ways to reduce the emissions “beyond the MACT Floor.” Thus, the case-by-case MACT assessment starts with a comparison of “similar sources” consistent with EPA’s proposed MACT and similar to other categorical MACT rules. In its proposed rule for EGUs, EPA categorized and sub-categorized similar sources by fuel rank and combustion type. EPA has also indicated that it is also appropriate to sub-categorize by design size, and size has been used in setting several MACT standards.

#### **1) Coal Rank**

In its proposed MACT, EPA sub-categorized coal-fired EGUs based on the rank of coal (e.g., bituminous, sub-bituminous, lignite, and waste coal).<sup>3</sup> EPA identified fuel rank as an important factor in assessing HAP control technology because of the chemistry of controlling trace amounts of emissions and the variability of HAPs in the various coal ranks. For example, it is recognized that bituminous coal typically contains more chlorine and other halogenated compounds than sub-bituminous coals. Not only do halides affect acid gas formation, higher halide content promotes mercury control. Additionally, coal rank is an important consideration when designing a boiler. For a specific steam generating capacity, a sub-bituminous boiler is normally designed taller and with a larger internal volume than one designed for bituminous coal. Boilers designed for lignite as a fuel are constructed even larger.

Data from the Electric Power Research Institute (“EPRI”) indicate that blends of sub-bituminous and bituminous coals comparable to the blends for which CSS6 is designed can exhibit combustion

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<sup>3</sup> See 69 Fed. Reg. 4652, 4662-63 (Jan. 30, 2004).

chemistry similar to bituminous coals as it relates to HAPs.<sup>4</sup> While CSS6 will be designed to burn up to 50 percent sub-bituminous coal, for purposes of this evaluation, the unit will be evaluated as burning eastern bituminous coal.

In the proposed rule, EPA also noted<sup>5</sup> that switching between coals is not a viable option because of the variation in Hg content and other key attributes in different seams of coal. EPA further expressed concerns that although one coal supply would have lower mercury, it may have other constituents that are higher than the proposed seam, and that this consideration would inject a regional difference among the sources nationwide. Such coal preferences would deplete the lower mercury seams and would also lead to regional disparities. In addition, mercury content can vary within a seam. EPA also recognized the design factors for coal included many considerations related to coal handling, processing, burner/firebox design, and wear and tear. In general, there could be a lack of viable alternative fuels that can be considered for pre-combustion measures. EPA decided that fuel switching is not an appropriate criterion for identifying the MACT Floor level of control for existing units. EPA further reviewed the applicability for considering alternate fuels for new units<sup>6</sup> and arrived at a similar conclusion and, again, concluded that precombustion techniques were not a viable option for setting MACT standards (i.e., for the MACT Floor or beyond the MACT Floor) for new units. Based on the EPA's own analysis this case-by-case MACT Assessment does not consider fuel switching -- or finding alternate fuels -- to be a viable control option for control of HAPs.

## **2) Type of Combustion**

In its 2004 proposed rule, EPA noted that the establishment of a MACT Floor for coal-fired EGUs had to take into account unit-specific coal properties and boiler technology. The EPA-proposed rule placed

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<sup>4</sup> EPRI, 2008. Pilot Evaluation of Impact of Chloride on SCR Mercury Oxidation – The Effect of Coal Blending. Electric Power Research Institute, Palo Alto, CA.

<sup>5</sup> 69 Fed Reg. 4669, January 30, 2004

<sup>6</sup> (69 FR 4678).

EGUs into categories based on combustion design and further sub-categorized by fuel rank. EPA's sub-categorization according to coal rank recognized that differences in coal rank reflect differences in, among other things, carbon content of the coal, volatile-matter content, heating value and agglomerating properties. In addition, EPA's sub-categorization accounts for the "significant impact" that "the rank of coal to be burned has . . . on overall plant design."<sup>7</sup> Indeed, "[t]he rank of coal to be burned greatly impacts the entire design process" as well as the design and operation of emission-control equipment.<sup>8</sup> In developing the proposed mercury MACT Floor for Electric Generating Units (EGUs), EPA also proposed limits for Integrated Gasification Combined Cycle ("IGCC") units separately from circulating fluidized bed ("CFB") or Pulverized Coal ("PC") units (69 Fed. Reg. 4652, 4662-63 (Jan. 30, 2004)). EPA also recognized in proposing the rule that further sub-categorization of boiler types might be appropriate. Based on its CAA § 112(n)(1)(A) determination, EPA proposed MACT limits only for mercury.<sup>9</sup> It did not propose a MACT Floor for other HAPs emitted from coal-fired EGUs, but acknowledged that sub-categorization by coal and boiler type would also affect MACT levels for HAPs other than mercury.

This assessment for CSS6 uses the sub-categorization methodology used in EPA's proposed rule and focuses on emission limits applicable to units of a similar combustion design as CSS6 – a PC boiler – and does not include a review of emissions for CFB or IGCC or lignite power plants.

### **3) Design Size**

In developing other MACT standards EPA has historically recognized that size is an important factor when designating sub-categories. With respect to EGUs, the design size of a unit is also important

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<sup>7</sup> See 69 Fed. Reg. at 4665.

<sup>8</sup> See *Id.*

<sup>9</sup> CAA § 112(n)(1)(A) states "...The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph." EPA had determined that regulation was only appropriate and necessary for mercury.

when determining the similarity of a source, since size affects the ability to control fuel consumption, air flow, overall cycle efficiency, and emission production – all factors that are relevant for comparison of performance of control technologies. For purposes of this Assessment, boilers of a similar size are those with a design output of 400 megawatts (MW) or more, based largely on a natural break in design sizes for EGUs that are under development today.

Thus, this assessment for CSS6 follows EPA's lead and focuses on emission limits applicable to units 400 MW and larger, with similar design and coal rank as CSS6 – a PC boiler burning eastern bituminous fuels. It does not include a review of emissions for CFB, IGCC facilities, or sub-bituminous-fired power plants.

**e. Practical Considerations in Comparing Data from Sources.**

It is also important to note several other practical factors in evaluating data from other sources and determining which one is the best controlled similar source.

**1) Achievability**

MACT limits must be continuously achievable. That is, they must be able to be met continuously under reasonably foreseeable worst-case conditions<sup>10</sup>. Thus, there is a need for a “safety margin” in setting MACT emission limits.<sup>11</sup> Coal quality, boiler operation, and the control devices are subject to variability in operation, and that variability needs to be addressed in developing emission rates. Coal properties that affect emissions vary widely from mine to mine, from seam to seam, and even within a single seam. Emission levels achieved from a mine-mouth plant, one that uses or contracts for coal from a single source, or even one that has been stack tested with only one particular coal are not necessarily a “similar source” to CSS6 which has been designed and permitted to utilize a range of bituminous and

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<sup>10</sup> Sierra Club v. EPA, 167 F.3d 658, 665 (D.C. Cir. 1999).

<sup>11</sup> Id.

sub-bituminous coal ranks, blended as needed to continuously meet simultaneous stringent permit limits.

In addition, EGU boilers experience different operating conditions, including, but not limited to, varying load operation and maintenance activities such as on line soot blowing. A unit must be able to attain those standards under all operating conditions. Thus, any enforceable permit limit must account for reasonable variations in coal properties, operating conditions, and other factors in order to ensure that MACT limits are continuously achievable.

## **2) Method of measurement**

Related to variability is the issue of how data is measured. In evaluating the emission rates that may have been achieved by other “similar” sources, it is important to compare units with similar methods of measurement. EPA described the need to address uncertainty and variability from emission test results in developing proposed MACT limits for new and existing EGUs<sup>12</sup>. As an example, hydrogen chloride (“HCl”), hydrogen fluoride (“HF”) and lead (“Pb”) emissions are directly related to the amount of the pollutant in the fuel, which also varies even within the same coal seam. Short-term stack test results do not adequately account for that variability. Stack testing for mercury represents a snapshot of mercury levels on a given day, based on the properties of the coal that is combusted on that day. A case-by-case MACT standard that will be continuously monitored with mercury CEMS is a fundamentally more stringent limit, since it will record the actual mercury emissions emitted by the facility, including all of the variations in operating conditions, coal properties, mercury content, unburned carbon in fly ash, sorbent reactivity, and other factors that will occur every day.

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<sup>12</sup> 69 FR 4678.

### 3) “Demonstrated in practice”

The MACT floor is defined as “[t]he emission limitation which is not less stringent than the emission limitation achieved in practice by the best-controlled similar source....” 15A N.C.A.C. 2D.1112(c)12, 40 C.F.R. § 63.41. The case-by-case MACT Floor should therefore be established based on the lowest permit limit for which the best-controlled similar source has demonstrated continuous compliance in practice, including consideration of the specific requirements for compliance demonstration (i.e., monitoring method). Thus, a permit limit from a unit that has not been constructed is not demonstrated. Moreover, even where a plant is operating, if there are only limited data that are not representative of worst-case properties and conditions, the limit or the emission level may not be demonstrated. This is especially important in light of the history of MACT, the regulatory history for EGUs, and the vacatur of EPA’s CAMR in 2008. There are few EGUs that have actual permit emission limitations for HAPs, and none that have long-term experience demonstrating continuous compliance with such a limit. Furthermore, operating mercury CEMs is not yet a mature technology for demonstrating compliance at an EGU as witnessed by the large number of problems experienced in the regulated community.

### 4) Enforceability

Also related to measurement is the issue of enforceability of a level that is below the applicability or quantification level for a method or pollutant. While these issues are technically complex, the simple fact is that it is not possible to enforce a limit below what can be accurately measured. The Ontario Hydro method, mercury CEMS (“Method 30A”) and the use of sorbent traps (“Method 30B”) are the three methods available for measuring mercury emissions.

There are well-documented limitations with the Ontario Hydro method<sup>13</sup> which is commonly used for mercury measurement. During the mercury ICR which preceded EPA’s proposed rule, stack tests

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<sup>13</sup> 40 C.F.R. Part 75 Appendix K, ASTM D6784-02

using this method at times calculated negative control efficiencies, meaning that the plant was emitting more mercury than was present in the coal being burned (which is presumably impossible). In addition, the method has an effective limit of detection that can be above the emission levels attained by some high performing facilities.

There is limited experience with operating mercury CEMS and there are concerns about the long-term reliability of these units, especially on wet stacks. Experience has shown that careful and labor intensive attention must be paid to operation, maintenance, and quality assurance/quality control (“QA/QC”) of mercury CEMS on a daily basis in order to obtain reliable data on units that have very low mercury concentration in the flue gas outlet. Several QA/QC issues associated with 40 C.F.R. Part 75 mercury monitoring system requirements remain unresolved. In particular, EPA has not developed a National Institute of Standards and Technology (NIST) traceable procedure for calibrating mercury CEMS. The 40 C.F.R. Part 75 procedures for certification of monitors at low concentrations (for example, where the mercury controls remove 80 percent or more of the mercury) allow a difference between the monitored values and the reference value of  $\pm 1 \mu\text{g}/\text{m}^3$ . Considering that a unit removing 80 to 90 percent of the mercury will emit at a concentration on the order of 1 to 2  $\mu\text{g}/\text{m}^3$ , this allowable tolerance may introduce a significant error in the CEMS data.

Sorbent trap systems may be used as a long-term monitoring device (installed in the flue gas for up to 30 days at a time) or as a means of conducting a reference method test over a short period. EPA Reference Test Method 30B uses paired sorbent traps to capture the mercury in a measured sample from a gas stream to determine the mercury concentration. The analytical procedures are NIST traceable and this method will produce highly accurate results if proper methods and QA are followed. The advantage over the OH test method is that sorbent traps do not require sensitive laboratory procedures in the field and the test runs can be conducted with less interference due to operator variance from test procedures. Sorbent traps used as a monitoring system operate on similar principles but simply collect mercury over an extended period to determine the average mercury concentration. The mass of mercury emitted is determined by measurement of the total flue gas flow

through the stack times the mercury concentration. The disadvantage of the sorbent trap method is that it can not provide any data on speciation of mercury. In addition, pretesting must be conducted to understand the range of the source's mercury concentration prior to collecting sorbent traps for compliance purposes.

For these reasons, comparison of source data must account for the potential deficiencies in measurement, the resulting uncertainty and the relative stringency of the test method.

**f. HAPs to be considered.**

In its proposed 2004 MACT rule, EPA established a MACT limit only for mercury for coal-fired EGUs. This Assessment goes beyond mercury and evaluates the HAPs that are expected to be emitted from sources similar to CSS6 and is based on EPA's studies conducted under CAA §112(n). The lists of HAPs that are potentially emitted from a coal fired power plant are provided in Table 1. As shown in the table, using these properties, all HAPs can be placed into the four categories to be evaluated: mercury; particulate HAPs; acid gas HAPs; and organic HAPs. Not all HAPs are reviewed in this assessment because they are emitted at levels below *de minimus* thresholds. For example, radionuclides are not included because EPA has determined that radionuclide emissions from coal-fired power plants need not be regulated under MACT because their emissions would not contribute appreciably to the existing background.

"The risks due to exposure to radionuclides from utilities are substantially lower than the risks due to natural background radiation. The average exposure to natural background radiation (excluding radon) for the U.S. Population has been estimated to be roughly about 100 mRems per year, which is about 67 times higher than the highest exposure due to utility radionuclide emissions."<sup>14</sup>

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<sup>14</sup> EPA "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress," EPA-453/R-98-004a at ES-23-24 (Feb. 1998).

Given the variety of coal ranks that are to be utilized and the suitable combustion technology, it is necessary to assess each HAP that may be emitted and to determine the physical and chemical properties of that HAP that can be utilized to separate it from the flue gas and to capture it.

EPA has indicated that HAPs can be characterized and controlled together using surrogates for measuring compliance when three factors are met: 1) the emissions are homogeneous and consistent; 2) the category and surrogate are similarly controlled; and 3) the surrogate emissions provide a representative measure of HAP emissions. The case-by-case MACT Assessment provided below for CSS6 assesses the control technologies that are applied to the separate groupings of HAPs and, where appropriate, the air pollutants that are used as surrogates. The groupings and surrogates for MACT Assessment are:

- Mercury (no surrogate);
- Particulate trace metals (filterable particulate matter as a surrogate);
- Acid Gases (SO<sub>2</sub> as a surrogate); and
- Organic HAPs (CO as a surrogate).

Each HAP category will be addressed to determine the best control mechanism and the best indicator to show maximum control.

**Table 1. List of HAPs Emitted from Coal-Fired Power Plants**

<b>Organics</b>		
Acetaldehyde	Formaldehyde	Total PCDD/PCDF
Acetophenone	Hexane	
Acrolein	Isophenone	<b>Acid Gases</b>
Anthracene	Methyl Bromide	Hydrogen Chloride
Benzene	Methyl Chloride	Hydrogen Fluoride
Benzo(g,h,l) perylene	MEK	
Benzyl Chloride	Methyl Hydrazine	<b>Particulate HAPs</b>
Biphenyl	Methyl Methacrylate	Antimony
Bis(2-ethylhexyl)phthalate	Methyl Tert-Butyl Ether	Arsenic
Bromoform	Methylene Chloride	Beryllium
Carbon Disulfide	Naphthalene	Cadmium
2-Chloroacetophenone	Phenanthrene	Chromium
Chlorobenzene	Phenol	Cobalt
Chloroform	POM	Lead
Cumene	Propionaldehyde	Manganese
Cyanide	Styrene	Nickel
2,4 Dinitrotoluene	Tetrachloroethylene	Selenium
Dimethyl Sulfate	Toluene	
Dioxins and Furans	1,1,1-Trichloroethane	
Ethyl Benzene	Vinyl Acetate	<b>Mercury</b>
Ethyl Chloride	Xylene	
Ethylene Dichloride		

The case-by-case MACT Assessment for each of HAP category is provided below, with a separate analysis for mercury emissions.

For the categories of HAP, other than mercury, the Assessment invokes the language of 15A N.C.A.C. 2D.1112(d)(3); 40 C.F.R. § 63.43 (d)(3) which authorizes a work practice where enforcement of emission limits is not feasible. Given the appropriate use of surrogates and the ability to continually monitor them, the assessment proposes controls of those surrogates to control the relevant HAPs.

### 3. Case-by-case MACT for Mercury

#### a. Chemistry and Physics of Mercury Removal

Mercury is present in coal in low concentrations. All the mercury in coal is vaporized to elemental mercury through the combustion process in a PC boiler. As the gas cools, chemical reactions occur and transform much of the mercury in the flue gas to two different forms: oxidized and particulate-bound, while the rest remains in elemental form. In general, typical particulate emissions control equipment is highly effective in controlling particulate-bound mercury and to a lesser degree oxidized mercury. Wet FGD systems have been shown to be very effective in removing oxidized mercury. The amount of mercury converted from the elemental to oxidized form increases when the flue gas from a bituminous fired unit that is oxidized passes through the SCR catalyst system. An analysis provided by Chu (2004)<sup>15</sup> concluded that

The SCR catalyst appears to increase mercury oxidation across the catalyst for bituminous coals, as well as for PRB/bituminous blends. For most bituminous coals, the mercury was primarily [oxidized mercury] (Hg(2)) at the SCR outlet, ranging from 60 to 90+%. While there is some variability among sites in the extent of mercury oxidation at the SCR outlet, most measurements indicated greater than 90% Hg(2) at the FGD inlet.

This oxidation is a critical component of the control effectiveness of the CSS6 emissions control system. Oxidation reactions significantly reduce the concentration of elemental mercury by the time the gases reach the stack. Equilibrium calculations suggest that mercuric chloride (“HgCl<sub>2</sub>”) will be formed at low temperatures in coal combustion flue gas. In addition, mercury oxide (“HgO”), and mercury sulfate (“HgSO<sub>4</sub>”) are formed in flue gas reactions. However, kinetic limitations to the oxidation of mercury in flue gas from coal-fired power plants are evident, and generally not all of the elemental mercury is oxidized in the flue gas.

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<sup>15</sup> Chu, P, 2004. Impact of SCR on Mercury Speciation and Removal. 2004 Update. Electric Power Research Institute, Palo Alto, CA.

The flue gas reactions that lead to the formation of mercuric chloride are through the reaction of atomic chlorine with elemental mercury. Oxidation of elemental mercury in a boiler occurs through two mechanisms – gas-phase reaction and catalyzed oxidation through contact with fly ash. Iron oxide and other constituents of fly ash have been shown to promote mercury oxidation. Finally, the presence of unburned carbon in the flue gas can facilitate gas phase adsorption of mercury on the surface of the carbon.

Bituminous coal contains higher levels of chlorine (i.e., approximately 300 to greater than 3000 ppmw) than other types of coal. Moreover, blends of bituminous and sub-bituminous coals with sufficient concentrations of chlorine act like bituminous coals, causing sufficient oxidation of mercury. Various sources, including EPRI, maintain that chlorine concentrations of at 300-500 ppmw or greater depending on calcium and other coal constituents are sufficient to promote oxidation of mercury. The amount of chlorine in the CSS6 coal blend even up to 50 percent sub-bituminous coal will provide significant quantities of chlorine for oxidation reactions to occur.

In summary, the amount of oxidized mercury and mercury adsorbed on the surface of particulate matter is influenced by four factors: 1) the coal chlorine content and ash composition; 2) the combustion efficiency and resultant unburned carbon in the fly ash; 3) the available sites on ash and unburned carbon not taken by sulfur trioxide (“SO<sub>3</sub>”); and 4) the temperature and residence time in the particulate control device.

**b. Control Technology**

- 1) Selective Catalytic Reduction (SCR), Spray Dryer Absorber (SDA), Fabric Filter (FF), and Wet Flue Gas Desulfurization (WFGD).**

In promulgating CAIR, EPA recognized the mercury reduction “co-benefits” of the controls for SO<sub>2</sub> and NO<sub>x</sub> that would be installed to meet the requirements of the Clean Air Interstate Rule. The proposed

SCR, SDA and WFGD technologies are known to control mercury. An EPA white paper<sup>16</sup> evaluated the level of mercury control with SCR, wet FGD and a particulate control device for PC units fired on bituminous coal. The best controlled bituminous-fired sources were estimated at 90-96 percent mercury removal based on limited stack testing, and EPA computed a representative compliance value at 86.7 percent using a statistical evaluation of the data variability. Data show that with existing bituminous units controlled for NO<sub>x</sub> (with SCR), SO<sub>2</sub> and particulate emissions, total mercury reductions can exceed 80 percent. Wet FGD systems have been shown to be very effective at capture of oxidized mercury. Greater than 90 percent removal of the oxidized mercury has been demonstrated with wet FGD from individual stack tests, with the actual long-term removal efficiencies under varying operating conditions. EPA's technical analyses related to developing the proposed standards have pointed out that control effectiveness for mercury emissions from coal-fired power plants varies significantly from source to source and from one coal supply to another.

Consistent with EPA's view and the mercury limits imposed in the Permit under CAMR and BACT regulations, the proposed emission control train was designed specifically to include the effects of the criteria pollutant control devices on mercury emissions. A portion of the elemental mercury released during combustion of coals will be oxidized in the boiler itself and further oxidized across the SCR. The oxidized forms of mercury are readily collected in downstream emission control system: the dry scrubber; the fabric filter; and the wet scrubber. Mercury capture will also be enhanced by the low exit temperature (less than 300<sup>o</sup>F) of the dry scrubber in the presence of fly ash. Finally, greater mercury removal is obtained with a fabric filter compared to an electrostatic precipitator ("ESP") because of enhanced gas-particle contact time in the filter cake on the surface of the bags in a fabric filter.

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<sup>16</sup> Memo, William H Maxwell to Robert Wayland, Energy Strategies Group, Office of Air Quality Planning and Standards, EPA. May 31, 2006.

Based on current controls to be used at CSS6 (SCR, SDA, FF, wet FGD), control of mercury emissions is expected to exceed 90 percent. The best-in-the-industry guarantee for mercury removal at CSS6 is 90 percent.

## **2) Activated Carbon**

Activated carbon injection (“ACI”) is an identified means of controlling mercury emissions from coal-fired boilers. Powdered activated carbon (“PAC”) sorbent is injected into the flue gas at a location in the duct upstream of the PM control device. The PAC sorbent binds with the mercury and is subsequently captured in the PM control device. In a similar fashion, unburned carbon in ash has also been observed to adsorb mercury on the surface of fabric filter bags.

The performance of activated carbon is related to its physical and chemical characteristics. Generally, the physical properties of interest for the activated carbon are surface area, pore size distribution, and particle size distribution. The capacity for mercury capture generally increases with increasing surface area and pore volume of the activated carbon. The ability of mercury and other sorbents to penetrate into the interior of a particle is related to pore size distribution. The pores of the carbon sorbent must be large enough to provide free access to internal surface area by HgO and mercury (II) (“Hg<sup>2+</sup>”) while avoiding excessive blockage by previously absorbed reactants. As mercury particle sizes decrease, access to the internal surface area of the particle increases along with potential adsorption rates.

Carbon sorbent capture of mercury is also dependent upon temperature, the concentration of mercury in the flue gas, the flue gas composition, and other factors. The selection of a carbon sorbent for a given application should take into consideration the total concentration of mercury, the flue gas composition, and the method of capture (i.e., ESP, FF or SDA). We note that the additional carbon from use of ACI may preclude the use of fly ash and gypsum produced in the boiler in the cement industry.

### 3) Multi-Pollutant Controls

Multi-pollutant controls refer to the ability of a piece of equipment or an equipment system to control more than one pollutant. The EPA initiated an Information Collection Request (“ICR”) data system aimed at gathering mercury emission data from coal-fired boilers from January 1, 1999, through December 31, 1999. EPA’s ICR data indicated that SCR increases oxidized mercury content in the flue gas by at least 35 percent for bituminous coals. Mercury control analysis for a new PC boiler, can reasonably assume the SCR will convert a minimum of 35 percent of the remaining elemental mercury in the flue gas to ionic mercury and that ionic mercury will be effectively collected in the fabric filter. Approximately 99.9 percent of fly ash and activated carbon (either unburned carbon particles or injected carbon) will be collected in the fabric filter.

A report by EPA<sup>17</sup> examined the control technologies for mercury removal, including wet or dry scrubbing, electrostatic precipitators or baghouses, and the addition of activated carbon injection on a range of coal-fired boilers. A concluding table showed that the “enhanced multipollutant controls” could be expected to control about 90 percent of the mercury for bituminous coals by 2010 and by 90 to 95 percent by 2015 as the industry applied aggressive research and development into optimization of these control systems. The report also concluded that the use of ACI could be expected to remove up to 90 percent of the mercury on a boiler equipped with a fabric filter (either alone or paired with an electrostatic precipitator). Given that CSS6 employs two separate sulfur dioxide controls (wet and dry) and that the system includes an SCR and a **fabric** filter, the technical assessment is that negligible further control of mercury can be expected and no added removal guaranteed by installing activated carbon injection on the existing CSS6 control system.

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<sup>17</sup> USEPA Control of Mercury Emissions from Coal Fired Electric Utility Boilers. (OAR-2002-0056. USEPA Air pollution Prevention and Control Division, Office of Research and Development, USEPA. Research Triangle Park, N.C.



source is Santee Cooper Unit 3, which has an enforceable emission limit of  $3.6 \times 10^{-6}$  lb/MMBtu, which can be recalculated to an output based rate of 0.036 lb/GWhour.

**d. Beyond the MACT Floor**

Table 2 provides a listing of mercury emissions for similar sources, and provides a listing of units that are considered for evaluating controls beyond the floor. The unique pollution control train at CSS6 is expected to surpass the removal efficiency of the MACT Floor. As designed by Duke and approved by the NC Utilities Commission, CSS6 will be a supercritical PC boiler capable of burning a wide variety of domestic bituminous and bituminous-sub-bituminous blends. EPA has determined that an uncontrolled mercury emission rate of 14.3 lb/TBtu represents the reasonable maximum value for an annual average for bituminous coal (equivalent to 0.20 ppm mercury in coal).<sup>18</sup> While this number represents a reasonably expected maximum mercury content in fuel, it is possible that some eastern bituminous coal that CSS6 might burn may have a higher mercury content. Duke expects to achieve a control effectiveness of at least 90 percent for the annual average, based on data provided by its vendors and considering the innovative integration of several control technologies that will be installed on the unit. However, because of accuracy issues associated with continuous monitoring to demonstrate compliance and the specific conditions under which vendor guarantees are given, it is unreasonable to commit to greater than 90 percent removal. Using the 90 percent control, Duke expects CSS6 to achieve a “beyond the MACT Floor” mercury limit of 0.014 lb/GW-hour. This emission limit is lower than an emission limit of any unit demonstrated in practice. It is also lower than the CAMR/BACT limit in the Permit and reflects Duke’s improved understanding of its projected coal quality and the equipment performance since the CSS6 air permit was issued.

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<sup>18</sup> Memo, William H Maxwell to Robert Wayland, Energy Strategies Group, Office of Air Quality Planning and Standards, EPA. May 31, 2006.

## 1) ACI

Duke also evaluated the possible use of ACI under the criteria in §112(g) – costs, energy requirements and non-air quality related environmental impacts and determined ACI is neither justified nor appropriate. It is not expected to measurably further reduce mercury, it is not cost-justified and it has adverse non-air quality environmental impacts. Other control options such as Bromated ACI and more exotic sorbents are under review and development in ongoing scientific studies. In addition, the additional halogen associated with Bromated ACI is not likely to provide any enhancement for a fuel that already has sufficient chloride content to affect mercury chemistry for optimal capture. For this application Duke determined that none of the other potential mercury reduction technologies can be classified as technically feasible because their cost and level of control effectiveness are so uncertain.

Given the high level of control that is expected from the co-benefits of the unique, state-of-the-art SCR, SDA, FF and WFGD air emission control train at Cliffside, ACI is expected to provide no incremental benefit.<sup>19</sup> To analyze cost effectiveness however, since ACI is the only feasible control technology that can be evaluated beyond the MACT Floor and beyond the enhanced controls that CSS6 will have in place, Duke considered ACI in a cost benefit analysis. Duke is unaware of ACI being guaranteed to remove greater than 90 percent Hg removal on a bituminous coal and even if such a guarantee were available, inaccuracies associated with continuous monitoring would make it suspect. A marginal level of improved control effectiveness, although it may overestimate actual levels of control, has been estimated and assumed based on ACI rates. The assessment estimates the cost for installing an ACI system, along with administrative and maintenance costs, as well as material cost for this level of control. Capital cost for equipment and installation of ACI is estimated to be

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<sup>19</sup> We note that the level of control that can be achieved by this technology on any particular coal is not clear. Control technologies and the merits of specific injection rates, ACI characteristics and other designs are still being tested for optimization and applicability to specific coals. The uncertainty related to controls on specific coals is a particular concern for low sulfur and low chlorine fuels. Nevertheless, some estimates of mercury control effectiveness are provided herein for potential controls based on ACI injection rates, but these are engineering estimates only, without specific confirmation for this coal source and this design operation.

\$2,835,000. The most significant operating cost of an ACI mercury control system is the rate of activated carbon injection into the system. The reagent costs were derived from review of the literature. The cost of activated carbon is estimated at approximately \$2,000/ton based on Duke's internal review of available suppliers. As a baseline, Duke used the expected mercury emission limit from the SCR, SDA, FF, WFGD train of  $14 \times 10^{-6}$  lb/MW-hour level. The cost analyses are provided in **Table 3** for the control rates. The incremental cost for achieving 0.0135 lb/GW-hour is over \$1,300,000 per pound of mercury controlled. The incremental cost for achieving additional mercury controls for the evaluation "beyond the MACT Floor" is dependent only on the increased amount of sorbent; however, there has been no guarantee or vendor information that this increased level could be achieved with activated carbon. Therefore these costs cannot be directly used in a MACT Assessment.

**Table 3. Cost Evaluation of Activated Carbon Injection (ACI) for Mercury Control**

		Emission Level (lb/MW-hour)	
		SDA/SCR/FF	Plus ACI
		/WFGD	
Total Gross MW =	918 MW	1.40E-05	1.35E-05
<b>CAPITAL COSTS</b>		14 X 10 <sup>-6</sup>	13.5 X 10 <sup>-6</sup>
<b>Direct Capital Costs</b>			
<b>Purchased Equipment Costs</b>			
Control Device w/ Instrumentation <sup>1</sup>		\$0	\$1,500,000
Shipping (5% Control Device Cost)		\$0	\$75,000
Foundation & Ductwork (6% Control Device Cost)		\$0	\$90,000
Taxes (0% of Purchased Cost)		\$0	\$0
<b>Total Purchased Equipment Cost (PEC)</b>		<b>\$0</b>	<b>\$1,665,000</b>
<b>Installation Costs</b>			
Foundations, supports (8% PEC)		\$0	\$133,200
Handling and Erection (14% PEC)		\$0	\$233,100
Electrical (4% PEC)		\$0	\$66,600
Piping (2% PEC)		\$0	\$33,300
Insulation (1% PEC)		\$0	\$16,650
Painting (1% PEC)		\$0	\$16,650
<b>Total Installation Costs</b>		<b>\$0</b>	<b>\$499,500</b>
<b>Total Direct Capital Cost (TDCC)</b>		<b>\$0</b>	<b>\$2,164,500</b>
<b>Indirect Capital Costs</b>			
Construction Management (10% TDCC)		\$0	\$216,450
Construction Field Expenses (5% TDCC)		\$0	\$108,225
Construction Fee (10% TDCC)		\$0	\$216,450
Contingency (3% TDCC)		\$0	\$64,935
Startup (2% TDCC)		\$0	\$43,290
Performance Testing (1% TDCC)		\$0	\$21,645
<b>Total Indirect Capital Cost</b>		<b>\$0</b>	<b>\$670,995</b>
<b>Total Capital Cost (TCC)</b>		<b>\$0</b>	<b>\$2,835,495</b>
<b>Annualized Capital Cost</b>	30 years 7.0 %	<b>\$0</b>	<b>\$228,502</b>
<b>OPERATING COSTS</b>			
<b>Direct Operating Costs</b>			
Operating Labor (2 hr/shift @ 3 shifts/day @ 365 days/yr @ \$16.00/hr)		\$0	\$35,040
Maintenance Labor (2 hr/shift @ 3 shifts/day @ 365 days/yr @ \$22.00/hr)		\$0	\$48,180
Supervision (15% Labor Costs)		\$0	\$12,483
Maintenance Materials (100% of Maintenance Labor)		\$0	\$48,180
Utilities			
Chemical Cost (PAC @ \$1.00/pound)		\$0	\$4,200,000
Electrical Cost		\$0	\$25,000
<b>Total Annual Direct Operating Cost</b>		<b>\$0</b>	<b>\$4,368,883</b>
<b>Indirect Operating Costs</b>			
Overhead (60% Labor)		\$0	\$49,932
Property Tax (1% TCC)		\$0	\$283,550
Insurance (1% TCC)		\$0	\$283,550
Administration (2% TCC)		\$0	\$56,710
<b>Total Annual Indirect Operating Cost</b>		<b>\$0</b>	<b>\$673,741</b>
<b>Total Annual Operating Cost</b>		<b>\$0</b>	<b>\$5,042,624</b>
<b>Total Annual Cost (Annualized Capital Cost + Operating Cost)</b>		<b>\$0</b>	<b>\$5,271,126</b>
<b>Total Mercury Emitted (lb/yr)</b>		<b>113</b>	<b>109</b>
<b>Total Mercury Controlled (lb/yr)</b>		<b>1037</b>	<b>1041</b>
<b>Incremental Pounds Mercury Controlled (lb/yr)</b>			<b>4.0</b>
Total Mercury		1150	1150
<b>Incremental Cost per Pound of Mercury Control</b>			<b>\$1,310,952</b>

No significant energy requirements were identified with respect to ACI; however, there are potential adverse environmental impacts. Injection of ACI will raise the carbon content of the flyash to levels where it is not suitable for beneficial reuse. Therefore, it will eliminate reuse of a possibly marketable by-product, which is commonly sold to cement manufacturing plants, and it will require the landfilling of the ash. As a result of the high cost of ACI for a very small reduction in mercury emissions, and due to the potentially adverse environmental impact, the extension of MACT for mercury further beyond the MACT Floor to include ACI is not justified. ACI is rejected as an additional control technology for mercury beyond the MACT Floor.

**e. MACT for Mercury**

Under this review, the existing SCR, SDA, FF, and WFGD is proposed as case-by-case MACT based on the incremental costs for controlling mercury with an emission limit of 0.014 lb/GW-hour, which is lower than the MACT Floor.

**4. Non mercury metallic HAPs**

**a. Chemistry and Physics of Control**

CSS6 will be a source of particulate matter, including non-mercury metallic HAPs. Non-mercury HAP metals such as lead, cadmium, beryllium and arsenic are trace elements contained in coal. When coal is burned in a pulverized coal-fired boiler, these metals may remain in the ash or may be vaporized depending on their individual boiling temperatures. However, as the gas stream cools within the heat transfer sections of the boiler, all metals present (with the exception of mercury, which has a very high vapor pressure) will exist as liquid or solid in the flue gas downstream of the air preheater. Metals that condense in the gas stream preferentially nucleate onto other fine particulate (such as fly ash) present in the gas stream. All HAP metals, with the exception of mercury, are liquid or solid at fabric filter temperatures, and will be collected essentially at the same efficiency as any other PM<sub>10</sub> material. So long as the evaluation of costs, energy requirements and non-air quality related environmental impacts does not reduce the emission rate below the MACT Floor, the application of BACT for filterable PM<sub>10</sub>

also constitutes case-by-case MACT for non-mercury PM<sub>10</sub>. Thus, in this assessment, control of filterable PM<sub>10</sub> is proposed as a surrogate of proper control technology design and performance for non-mercury HAP metals, since they provide the same ability to capture particulate matter and provide analogous representative measurement.

## **b. PM Control Alternatives**

There are three types of particulate control technology: (1) fabric filters, (2) electrostatic precipitators, and (3) other wet technologies.

### **1) Fabric Filter**

Many of the units listed in the EPA's BACT/LAER Clearinghouse use fabric filters to achieve the top level of control. Fabric filters are widely used for particulate control from pulverized coal boilers and are capable of over 99 percent particulate control efficiency. According to EPA's Fabric Filter Fact sheet ([www.epa.gov/ttn/catc/dir1/ff-pulse.pdf](http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf)), "flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms." Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 13 to 31 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolated compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

The advantages of fabric filters include:

- 1) High collection efficiency for a broad range of particle sizes;
- 2) Flexibility in design (various methods of cleaning and filter media);
- 3) Wide range of volumetric capacities;

- 4) Reasonable pressure drops and power requirements; and
- 5) Ability to handle a wide range of solid materials.

Some disadvantages of fabric filters are as follows:

- 1) Potential bag damage due to abrasion, wear or fire; and
- 2) Wet particles can agglomerate on a filter cloth if the waste gases are at a temperature close to their dew point.

## **2) Electrostatic Precipitators (ESPs)**

ESP technology is applicable to a variety of coal combustion sources. ESPs remove particulate matter from the flue gas stream by charging fly ash particulates with a high direct current (“DC”) voltage and attracting these particles to charged collection plates. A layer of collected particulate forms on the collecting plates (electrodes) and is removed by rapping the electrodes. The collected particulate drops into hoppers below the precipitator and is periodically removed from the fly ash handling system.

Because of their modular design, ESPs can be applied to a wide range of system sizes with little or no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies of approximately 95 percent for fine particles (less than 0.1 microns) and greater than 99 percent for coarse particles (greater than 10 microns).

ESPs are considered a technically feasible option for the proposed CSS6 boiler. However, dry ESP's are not as well suited as fabric filters for collateral removal of pollutants such as H<sub>2</sub>SO<sub>4</sub>, HCl, HF, SO<sub>2</sub> and Hg in the presence of solid reagents such as lime, since they do not enable the superior gas-to-solids contact that occurs when all of the boiler flue gas is forced through a filter cake of solids

containing these unreacted reagents on the surface of the bags. Dry ESP's are also considered inferior to fabric filters at capturing the finest fractions of filterable particulate (PM<sub>10</sub> and PM<sub>2.5</sub>) since particles in this size range have a very low terminal velocity, meaning that the electrostatic forces in an ESP may not be sufficient to overcome the tendency of very small particles to remain entrained in the flue gas stream. However, ESP's have been demonstrated to be very effective at overall PM capture through careful consideration of design factors, and both ESPs and Fabric filters have been considered by EPA to be suitable technologies for control of filterable particulates.

Wet ESPs have been applied to unique situations for control of soluble gases aerosols, and particulate matter. These units are not focused on control of particulate matter alone, and have not been applied to coal-fired EGUs to control particulate matter. There are no known applications where wet ESPs have been used as a primary particulate collection device on a coal-fired utility boiler. These units are not further developed as a control option for particulates from coal-fired EGUs. In the case of CSS6, they offer negligible added benefit since the pollutants they remove will have already been effectively reduced by other components.

### **3) Other wet controls.**

Other wet control techniques (Venturi or other high-energy scrubbers), on the other hand, do not represent a recently applied or demonstrated control technique for coal-fired boilers and do not offer more stringent levels of control of particulate matter than fabric filters.

A review of EPA's RACT/BACT/LAER Clearinghouse indicates several levels of filterable particulate matter control that may be achieved for pulverized boilers. Emission levels and control technologies have been identified and ranked in **Table 4**.

Table 4. Ranking of Particulate Control Technology Options for Pulverized Coal-Fired Boilers

Control Technology Option	Emission Level (lb/MMBtu)	Technically Feasible for Pulverized Coal-fired Boilers?
Fabric Filter	0.01 to 0.02 for filterable PM	Yes
Electrostatic precipitator	0.015 to 0.025 for filterable PM	Yes
High energy wet scrubber	Not determined	No applications in the last 15 years to large coal-fired boilers
Emission levels represent target steady-state values at base load, for front-half (filterable) only, as these control technologies are not designed to remove condensable PM.		

**c. Best Controlled Similar Source – the MACT Floor**

Table 5 provides a list of similar units with established emission limits for filterable PM<sub>10</sub>. A review of the PM emission limits from “similar sources” (i.e., PC boilers greater than 400 MW) shows that the lowest PM emission limit is 0.018 lbs/MMBtu. This is the MACT Floor for PM HAPs.

**Table 5  
Comparison of Duke CSS6 to Similar Sources for Filterable PM<sub>10</sub> Emissions**

	Status	MW	MMBtu	PM <sub>10</sub> lb/MMBtu
Duke CSS6	P	800	7850	0.012
<b>Operating Units (MACT FLOOR)</b>				
Clover	O	440	4085	0.018
Santee Cooper, Unit 3 (Cross)	O	640	5700	0.018
<b>Permitted Units (Not OPERATING)</b>				
Sandy Creek	P	860	8185	0.015
Longview Maidsville	P	600	6114	0.018
Thoroughbred Generating	P	750	7443	0.018
Elm Road	P	727	6180	0.018
Prairie State Generating Station	P	750	7450	0.015

**d. Beyond the MACT Floor**

Fabric filters and electrostatic precipitators (ESP's) represent technically feasible options for the control of particulate matter from coal-fired boilers. No additional control technology is available to provide emission limits beyond the MACT Floor. The top level of control for PM<sub>10</sub> for recent BACT determinations, including the BACT analysis for CSS6, is 0.012 lb/MMBtu for filterable PM<sub>10</sub> which represents the case-by-case MACT Floor for PM<sub>10</sub> for this particular project.

**e. MACT for Non-Mercury Metallic HAPs**

Based on numerous projects using fabric filters, Duke proposes to use a fabric filter as the case-by-case MACT for PM filterable emissions to 0.012 lb/MMBtu based on a periodic Reference Method 5 stack test. The application of this control technology will also achieve Maximum Achievable Control of non-mercury metallic (particulate) HAP.

**5. MACT for HAP Acid Gases**

**a. Chemistry and Physics of Control**

Acid gas emissions include Sulfuric Acid Mist ("H<sub>2</sub>SO<sub>4</sub>"), and two HAPs, Hydrogen Chloride ("HCl"), and Hydrogen Fluoride ("HF"). This assessment focuses on the acid-gas HAPs, which are controlled in coal-fired EGUs using the same technology employed to control SO<sub>2</sub>.

Emissions of acid gas HAPs are generated in fossil fuel-fired sources from the release of chlorine and fluorine present in the fuel. Since only trace amounts of these two elements are present in coal, it is presumed that they are all released during combustion to form the acid gases, HCl and HF.

**b. Control Technology**

Generally, the control technologies applied to SO<sub>2</sub> emissions are also highly effective in controlling acid gases. Post-combustion SO<sub>2</sub> controls applicable to PC boilers are a spray dryer absorber ("SDA") acid scrubbing system using reagents such as lime, limestone, sodium bicarbonate or magnesium oxide, or a wet FGD system using lime, magnesium enhanced lime and limestone, or in some cases ammonia,

to control SO<sub>2</sub> emissions. Given the reactivity and solubility of these acid gases in comparison to SO<sub>2</sub>, HCl and HF are preferentially controlled by the acid gas systems (the CSS6 WFGD) controlling the SO<sub>2</sub>. Spray dry systems will also remove a large percentage of the HCl and HF.

### 1) **Wet FGD**

The most frequently utilized wet FGD technology is the wet limestone spray tower system. Typically, the flue gas enters at the bottom of the absorber tower, continues vertically through a slurry spray of the pulverized limestone, passes through a mist eliminator to control the re-entrained slurry drops, and then exits the tower. Limestone (calcium carbonate) reacts with the sulfur dioxide to form calcium sulfite. The calcium sulfite may then be oxidized to form calcium sulfate, since it is easier to de-water than calcium sulfite. This can be achieved by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank.

To fully utilize the limestone, the slurry is re-circulated through the tower and a bleed stream is taken off for de-watering. The bleed stream can be de-watered using a variety of techniques, including thickeners, centrifuges and vacuum filters. The final slurry may contain anywhere from 10 to 40 percent solids by weight. Removal of the calcium sulfate (gypsum) solids from the slurry allows recycling of this material into wallboard as Duke intends to do with the CSS6 byproduct.

Wet scrubbers can utilize lime or magnesium enhanced lime rather than limestone. In these cases some of the lime (calcium oxide) becomes calcium hydroxide in water. The slurry of calcium hydroxide and lime is fed to the spray tower. As it circulates, the slurry absorbs other reaction products which can increase its scrubbing capability. In these applications there can be a cost trade off between lower capital costs of a magnesium enhanced scrubber vs. the lower reagent cost of a limestone scrubber. Recently scrubber installations have more frequently used limestone based units.

Wet FGD systems control acid gases downstream of a conventional particulate control device such as a fabric filter or electrostatic precipitator. Wet FGD systems are highly effective for control of HCl and HF due to the solubility of these gases as well as the control of flue gas temperature and the ability of

the chemistry in the scrubber to promote reactions that remove HCl and HF as salts. Removal efficiency greater than 95 percent is readily achievable for HCl and HF with a wet FGD system.

## **2) Spray Dryer Absorber**

The spray dryer absorber is located upstream of the particulate collection system, and incorporates the use of a fabric filter as BACT for PM<sub>10</sub> (PM<sub>2.5</sub>), Hg, fluorides and H<sub>2</sub>SO<sub>4</sub>. The flue gas first passes through a spray dryer vessel where it encounters a fine mist of lime slurry. The lime slurry is injected into the spray dryer absorber through either a rotary atomizer or fluid nozzles. The moisture in the droplets evaporates and calcium reacts with the HCl and HF in the flue gas to form solid calcium salts. The flue gas is cooled to approximately 18 to 30 °F above the adiabatic saturation of the flue gas in a SDA system that is designed as the primary sulfur dioxide (“SO<sub>2</sub>”) control device. The calcium salts have a moisture content of approximately 2 to 3 percent, which falls to 1 percent before reaching the particulate control device. In the case of CSS6, the approach to saturation temperature will be higher and will be set at a point that assures effective capture of sulfur trioxide (“SO<sub>3</sub>”). When a fabric filter is used as the particulate control device, it allows for further reaction of the lime with any remaining acid gases. This is due to the layer of porous calcium oxide filter cake on the surface of the filter bags that all flue gas must pass through. This increases the control efficiency of sulfuric acid mist, acid gases, fine particulate and mercury. The removal efficiency of HCl and HF in a spray dryer depends on the approach to saturation and amount of unreacted lime available. The CSS6 SDA system is likely to achieve 50 percent to 70 percent removal of HCl and of HF.

## **3) Wet FGD with a Polishing Wet ESP (WESP)**

Certain coal-fired boilers burning higher sulfur coals utilizing SCR and wet FGD (and no SDA) have evaluated Wet ESP as a potential control of sulfuric acid mist. Several permits have been issued (e.g., Thoroughbred in Kentucky) requiring a polishing WESP to remove residual sulfuric acid mist downstream of a wet FGD. While WESP is in theory an effective control device for collection of aerosols such as sulfuric acid mist, it is a technology that has not been demonstrated in practice on utility-scale coal-fired boilers similar to the CSS6 boiler. In addition its performance on the more

reactive HF and HCl acid gases is not certain for installations using high efficiency FGD systems. For a control stream following a SDA and a wet FGD, it is not likely that the installation of a wet ESP will provide any additional control of these acid gases. In instances where a SDA is employed upstream of a fabric filter, a wet ESP will be ineffective since those devices will already remove most of the HCl and HF.

**c. Best Controlled Similar Source- the MACT Floor**

The ranking of available SO<sub>2</sub> and acid HAP control technologies, shown in **Table 6**, must take into consideration multiple variables including sulfur content of the coal, percent removal and the resulting emission rate (lb/MMBtu).

**Table 6 - Ranking of SO<sub>2</sub> and Acid HAP Control Technologies for Pulverized Coal Boilers**

<b>Control Technology</b>	<b>Typical SO<sub>2</sub> Emission Level<sup>1</sup> for Bituminous sources (lb/MMBtu)</b>	<b>Technically Feasible on PC Boilers</b>
Wet Scrubber	Depends on Coal Sulfur Content (0.12-0.18)	Yes
Spray Dryer Absorber	Depends on Coal Sulfur Content (0.12 – 0.18)	Yes
Limestone Injection	Undetermined for acid gases	Yes

<sup>1</sup>. Emission levels represent steady state values.

The emission rate for the best controlled similar source demonstrated in practice, using SO<sub>2</sub> as a surrogate is shown in Table 7. The MACT Floor for SO<sub>2</sub> is 0.13 lb/MMBtu based on the emissions for Santee Cooper Unit 3.

**Table 7**  
**Comparison of Duke CSS6 to Similar Sources for SO<sub>2</sub> Emissions**

	Status	MW	MMBtu	SO <sub>2</sub> lb/MMBtu
Duke CSS6	P	800	7850	0.12
<b>Operating Units (MACT FLOOR)</b>				
Clover	O	440	4085	0.156
Santee Cooper, Unit 3 (Cross)	O	640	5700	0.13
<b>Permitted Units (Not OPERATING)</b>				
Sandy Creek	P	800	8185	0.12
Longview Maidsville	P	600	6114	0.12
Thoroughbred Generating	P	750	7443	0.167
Elm Road	P	727	6180	0.15
Prairie State Generating Station	P	750	7450	0.182

**d. Beyond the MACT Floor**

The lowest emission limits for SO<sub>2</sub> from the proposed PC boilers is in the range of 0.12 – 0.182 lb/MMBtu on a 30-day rolling average to be measured by continuous monitoring. The emission limit established for CSS6 is 0.12 lb/MMBtu based on the need to handle high sulfur coals and use of a high efficiency wet FGD system. Because the 0.12 lb/MMBtu SO<sub>2</sub> limit on CSS6 represents a very high degree of control which can only be achieved through use of a high efficiency wet FGD system, achieving the SO<sub>2</sub> compliance limit assures that the HCL and HF emissions control will be achieved since those are preferentially removed in the scrubber. The selection of SO<sub>2</sub> control technology for the CSS6 boiler was a case-by-case determination based on using high sulfur coal and removing the acid gases with a spray dryer system followed by a fabric filter, followed by a wet scrubber to remove the bulk of the remaining SO<sub>2</sub> gas. Duke is not aware of any available methods that could reduce acid gas emissions at the CSS6 beyond the combination of controls which are included in the existing permit.

**e. Case-by-case MACT for HF**

Emissions of fluorides are generated in fossil fuel-fired sources from fluorine present in the fuel. For the CSS6 boiler, the same SDA/FF/wet FGD system designed to control other acid gases will also control fluoride emissions through the injection of lime before the fabric filter and wet removal of remaining HF in the wet FGD. This control technology is proposed as MACT for HF.

**f. Case-by-case MACT for Hydrochloric Acid (HCl)**

Emissions of chlorides are generated in fossil fuel-fired sources from chlorine present in the fuel. For the CSS6 boiler, the same SDA/FF/wet FGD system designed to control other acid gases will also control chloride emissions through the injection of lime before the fabric filter and wet removal of remaining HCl in the wet FGD. This control technology is proposed as MACT for HCl.

**6 Case-by-case MACT for Organic HAPs**

**a. Chemistry and Physics of Control**

Combustion is a thermal oxidation process in which carbon, hydrogen, and sulfur contained in a fuel combine with oxygen in the combustion zone to form CO<sub>2</sub>, H<sub>2</sub>O, and SO<sub>2</sub>. CO is generated during the combustion process as a result of incomplete thermal oxidation of the carbon contained within the fuel. Organic HAPs are also generated due to incomplete combustion of fuel. High levels of CO and organic HAP emissions result from poor burner design or sub-optimal firing conditions. With combustion technology/design control, formation of CO and organic HAPs in the PC boiler is minimized by good combustion efficiency through optimum design and operation. This includes proper air-to-fuel ratios, and a boiler design that provides the necessary temperature, residence time and mixing conditions in the combustion zone.

Care must be taken when incorporating combustion design changes to reduce both NO<sub>x</sub> and CO or organic HAP emissions. Combustion modifications associated with reduction of CO and organic HAP emissions can increase NO<sub>x</sub> emissions and vice versa. For example, the use of low-NO<sub>x</sub> burners reduces flame temperature and thus reduces the NO<sub>x</sub> formation in the combustion zone, but

the same technique also leads to increases in products of incomplete combustion such as CO and organic HAP. A good balance between these air pollutants must be achieved in order for combustion modification to be useful. Control of incomplete combustion to control organic HAP emissions are accomplished in the same way CO emissions are controlled: by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

#### **b. Control Technology**

Similar to the other products of incomplete combustion ("PIC"), such as CO, organic HAP emissions from coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All coal-fired boilers that were evaluated under the BACT analysis utilize front-end methods such as combustion control wherein organic HAP formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse for coal-fired boilers utilize combustion control techniques as BACT for CO.

##### **1) Combustion Control**

Combustion control refers to the optimization of the design, operation, and maintenance of the furnace and combustion system, and it is the primary mechanism available for lowering CO and organic HAP emissions. The furnace/combustion system design on modern PC-fired utility boilers provides all of the factors required to facilitate complete combustion. These factors include continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion chamber. As a result, a properly designed furnace/combustion system is effective at limiting CO and organic HAP formation by maintaining the optimum furnace temperature and amount of excess oxygen.

Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of CO and organic HAP emissions will lead to an increase of NO<sub>x</sub> emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO and organic HAP emissions are reduced as much as possible without causing NO<sub>x</sub> levels to significantly increase. Proper operation and maintenance of the

furnace/combustion system will help to minimize the formation and emissions of CO and organic HAP by ensuring that the furnace/combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel condition at the burner, and maintaining the fans and dampers in proper working condition. Regardless of the effects of combustion control for NO<sub>x</sub>, combustion of fuel in a high efficiency boiler is extremely effective at destroying or preventing the formation of any organic HAPS. In fact, combustion of hazardous organic chemicals in a high efficiency boiler is a recognized means of safe and effective disposal and heat recovery, typically assuring much greater than 99 percent destruction of any hazardous organic materials. The minor impacts on CO or organic HAP emissions related to NO<sub>x</sub> control do not render combustion control of organic HAPS as unsuitable or less than effective.

## **2) Add-On Emission Controls**

Catalytic and thermal oxidation are post combustion control techniques for reducing emissions of CO and organic HAPs from a wide range of sources. These control devices are generally limited to sources that have exhaust streams with relatively high levels of CO or organic HAPs and flow rates well below those of utility boilers. Given the high temperature and design of EGUs, the emission of these constituents is well controlled by the use of good combustion practices. There are no known installations of catalytic or thermal oxidation units to treat the flue gas of any large coal fired EGU,. Given the nature of the flue gas stream, neither catalytic oxidation nor thermal oxidation are technically feasible for application to utility-scale coal-fired boilers.

### **c. Best Controlled Similar Source – the MACT Floor**

A review of EPA's RACT/BACT/LAER Clearinghouse indicates levels of CO control which may be achieved for pulverized coal-fired boilers. Emission limits and control technologies have been identified and ranked in **Table 8**. Table 9 provides a list of CO emission limits for similar sources. Emissions from CSS6 are at or very near the lowest level of CO emissions for these similar sources.

**Table 8. Ranking of CO Control Technology Options for Pulverized Coal-Fired Boilers**

<b>Control Technology Option</b>	<b>Emission Level (lb/MMBtu)</b>	<b>Technically Feasible for Pulverized Coal-fired Boilers?</b>
Combustion control	0.10	Yes
Oxidation catalyst	Not determined	No

**Table 9  
Comparison of Duke CSS6 to Similar Sources for CO Emissions**

	Status	MW	MMBtu	CO lb/MMBtu
Duke CSS6	P	800	7850	0.12
<b>Operating Units (MACT FLOOR)</b>				
Clover	O	440	4085	0.10
Santee Cooper, Unit 3 (Cross)	O	640	5700	0.16
<b>Permitted Units (Not OPERATING)</b>				
Sandy Creek	P	860	8185	0.15
Longview Maidsville	P	600	6114	0.11
Thoroughbred Generating	P	750	7443	0.10
Elm Road	P	727	6180	0.12
Prairie State Generating Station		750	7450	0.12

Pulverized coal-fired boilers are designed specifically for efficient fuel combustion with thorough mixing and residence time at temperature, plus staged combustion. This level of combustion control represents BACT for the proposed boiler. Based on the emissions limits from the best controlled similar source demonstrated in practice (Clover), the MACT Floor is 0.10 lb/MMBtu.

**d. Beyond the MACT Floor**

The only practical or demonstrated-in-practice measures to control organic HAP emissions from coal-fired boilers is good combustion. Combustion control, and the resulting optimized emission rate to minimize formation of organic HAP and CO, while also minimizing NO<sub>x</sub>, therefore represents BACT for the CSS6 boiler. The lowest CO emission limit listed in EPA's RACT/BACT/LAER Clearinghouse is

0.10 lb/MMBtu for the Clover and Thoroughbred Generating Stations. No other control technology is available to provide controls beyond the MACT Floor for CO, and no other permit limits have been established that are beyond the identified MACT Floor for similar units.

**e. MACT for organic HAPs**

Case-by-case MACT and the top level of control for organic HAPs is good combustion control to limit CO to 0.10 lb/MMBtu.

**7. Summary**

Table 10 provides a summary of the case-by-case MACT Assessment for CSS6.

**Table 10. Summary of Case-by-Case MACT Assessment**

<b>HAP</b>	<b>Control Technology Employed by Best Controlled Similar Source Demonstrated in Practice</b>	<b>Control Technology Employed by CSS6</b>	<b>MACT-Equivalent Emission Limit</b>	<b>Performance Indicator (or surrogate)</b>
<b>Hg</b>	SCR, SDA, FF	SCR, SDA, FF, wet FGD	0.014 lb/gross GWH, 12-month rolling average	Hg CEM
<b>HCl</b>	SDA / FF	SDA / FF, wet FGD	Existing SO <sub>2</sub> limit of 0.12 lb/MMBtu, 30-day average	SO <sub>2</sub> CEM
<b>HF</b>	SDA / FF	SDA / FF, wet FGD	Existing SO <sub>2</sub> limit of 0.12 lb/MMBtu, 30-day average	SO <sub>2</sub> CEM
<b>HAP Metals</b>	FF	FF	Existing PM limit of 0.012 lb/MMBtu	Stack Test for Filterable PM
<b>Organic HAPs</b>	Combustion Control	Combustion Control	CO limit of 0.10 lb/MMBtu	Stack Test for CO

## 8. Case-by-case MACT for Limited Use Oil-Fired Auxiliary Boiler

On September 13, 2004, USEPA promulgated MACT standards for industrial, commercial, and institutional boilers and process heaters in 40 C.F.R. 63 Subpart DDDDD (Boiler MACT). This rule was later vacated on July 30, 2007, by the U.S. Court of Appeals for the District of Columbia Circuit (Natural Resources Defense Council v. EPA, D.C. Cir., No. 04-1385) on the basis that EPA's definition of "commercial or industrial waste" was too narrow in scope and inconsistent with the plain language of Section 129 of the CAA. This improperly limited the number of solid waste incineration units subject to Section 129 and subsequently those subject to Boiler MACT. However, this decision did not refute the emission limitations and work practice standards established in Boiler MACT unrelated to commercial and industrial solid waste incineration ("CISWI"). Therefore, CSS6 proposes to adopt the applicable emission limitations and work practice standards as MACT for the auxiliary boiler.

The Boiler MACT establishes emission limitations for mercury, selected metals, inorganic HAPs (mainly acid gases), and organic HAPs based on a sub-category determined by fuel type and use. The auxiliary boiler proposed for Unit 6 is rated at 190 MMBtu/hr and operates no more than 10 percent of the hours per year per federally enforceable conditions (See Permit Condition Part 1, Section 2.1.K.5(c)). As such, this boiler is considered a limited-use liquid-fuel unit as defined in 40 C.F.R. 63.7575. Accordingly, this unit has an emission limitation on the following per 40 C.F.R. 63.7500 (a)(1) and Table 1 to 40 C.F.R. 63 Subpart DDDDD:

PM - 0.03 lb/MMBtu

HCl - 0.0009 lb/MMBtu

CO – 400 ppmv (@3% oxygen).

The PM emission limits are indicative of controls on trace metal HAPs; HCl is identified as a control parameter and is an indicator for other acid gases (HF). Because CO is a good indicator of

incomplete combustion, there is a direct correlation between CO and organic HAP formation. Thus, this limit serves as an indicator for organic HAP including dioxin-furans (see 69 FR 55223). CSS6 will demonstrate compliance with this limit by an initial performance test as required by 40 C.F.R. 63.7520 and Table 5 of 40 C.F.R. 63 Subpart DDDDD.

Permit Condition Part 1, Section 2, 2.1.K.5(b) limits the filterable particulate matter to 0.014 lb/MMBtu, which will demonstrate compliance with that MACT standard. Emission limits for HCl and CO will be incorporated into the permit as part of compliance with case-by-case MACT. Given the detailed EPA analysis in developing the MACT for these units, this application incorporates those findings as demonstration of case-by-case MACT for oil fired limited use boilers.