UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Fact Sheet

Architect of the Capitol

Capitol Power Plant
25 E Street S.E.
Washington, D.C.

EPA Draft Permit
Permit Number EPA-R3-PAL-001

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I. General Information

Name of source:	Capitol Power Plant
Applicant's Name:	Architect of the Capitol
Location:	Washington, D.C.
Address:	25 E Street S.E. Washington, D.C. 20003
Application Prepared by:	Trinity Consultants 5320 Spectrum Drive, Suite A Frederick, MD 21703
Draft permit number:	EPA-R3-PAL-001
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The Capitol Power Plant (CPP) became operational in 1910 and was originally designed to provide heat and electricity to the U.S. Capitol. CPP eliminated electrical energy production in 1951, and the power plant currently provides steam and chilled water to 23 facilities on Capitol Hill, including the House and Senate office buildings, the Supreme Court, and the Library of Congress.

On March 28, 2012, the Architect of the Capitol (AOC) submitted an application to EPA to construct and operate a cogeneration plant at the U.S. Capitol Power Plant. As part of this application, the AOC asked EPA to establish plantwide applicability limits (PALs) for those regulated NSR pollutants that would otherwise cause a significant increase in emissions due to the project. The pollutants included $PM_{2.5,}$ $PM_{10,}$ NO_2, greenhouse gases (GHGs), and NO_x as a precursor for ozone. As explained later in this fact sheet, EPA is not authorized to issue PALs for nonattainment pollutants in the District. Therefore, EPA is taking action only the elements of the application related to PALs for the PSD pollutants and is not taking any action on the application for a permit to construct the cogeneration plant. The PSD pollutants for which a

PAL has been requested include PM_{10}, NO_2 and GHGs. The application was deemed complete by EPA on May 3, 2012.[1]

EPA has prepared this Fact Sheet and draft permit for the Capitol Power Plant project as required by 40 C.F.R Part 124 - Procedures for Decision Making.

II. Legal Authority

A. General

The District of Columbia is attaining all of the National Ambient Air Quality Standards (NAAQS) with the exception of $PM_{2.5}$ and ozone. As required under §110(a)(2)(C) and §173, the District has an approved non-attainment new source review (NSR) program for major stationary sources in their State Implementation Plan (SIP) at 40 C.F.R. Part 52 Subpart J. Therefore, the DDOE is the NSR permitting authority for NO_x and VOCs as precursors to ozone, and NO_x and SO_2 as precursors to $PM_{2.5}$, as well as direct emissions of $PM_{2.5}$.

The District does not have an approved Prevention of Significant Deterioration (PSD) Program and is currently under a Federal Implementation Plan (FIP) for PSD (40 C.F.R. 52.499). Consequently, EPA is the PSD permitting authority for the attainment pollutants, as well as all other non-criteria NSR regulated pollutants, such as GHGs. EPA's authority to issue PSD permits under a FIP has been delegated to the Director of the Air Protection Division.

B. PALs

EPA intends to issue the PALs under the authority of 40 C.F.R. § 52.21(aa). Generally, the federal regulations state that PALs may be issued via a major NSR permit, a minor NSR permit, or a Title V permit. (40 C.F.R 52.21(aa)((2)(ix)). Although the District does have an approved title V program, it does not have the underlying authority to issue a PAL permit for PSD pollutants under the permitting programs approved in their State Implementation Plan (SIP). Therefore, EPA will rely on the authority of 40 C.F.R. §§ 52.21 and 124 to issue the PALs.[2]

III. Public Notice Procedures

The EPA has followed the requirements for Procedures for Decisionmaking at 40 C.F.R.124 in issuing a permit under the authority of 40 C.F.R. 52.21. In accordance with those procedures, EPA Region III is giving public notice of the 30-day comment period concurrent with release of

[1] See letter dated May 3, 2012 from Diana Esher, Director, Air Protection Division, to Christopher Potter, Acting Director, Utilities and Power, Architect of the Capitol.

[2] See 77 FR 41051, 41059 (July 12, 2012) (In finalizing the GHG PAL changes in Step 3 of the Tailoring Rule, EPA explained that "permitting authorities implementing the federal PSD program will be able to use the authority provided to them under 40 CFR 52.21, including the changes finalized in this rule, and corresponding permitting procedures (such as those in 40 CFR part 124) to issue PAL permits for GHGs in a manner consistent with PAL permits issued for regulated NSR pollutants other than GHGs.")

this Fact Sheet.[3] A public hearing is also announced in the public notice and will be held on October 1, 2012 from 5:00 PM to 7:00 PM at the Washington Council of Governments, located at 777 North Capitol Street, NE, Suite 300, Washington, DC 20002.

IV. PAL Background

The 2002 NSR Reform Rules, among other things, allowed major stationary sources to comply with a PAL to avoid having a significant emissions increase that triggers the requirements of the major NSR program. The 2002 NSR Reform Rules became effective on March 3, 2003, and the PAL provisions were upheld on June 24, 2005. *See New York v. United States*, 413 F.3d 3 (*New York I*).

The PAL regulations were revised in Step 3 of the GHG Tailoring Rule in order to provide for better implementation of PALs for GHGs.[4] Step 3 of the Tailoring Rule revised the PAL regulations to allow GHG PALS to be established on a CO_2e basis. The revisions allow a permitting authority to add 75,000 tpy CO_2e to a source's CO_2e baseline actual emissions to establish the PAL level, because the Tailoring Rule established 75,000 tpy CO_2e as the appropriate rate of emissions increase for existing sources of GHGs to be subject to regulation.

As EPA explained when finalizing the PAL revisions to better address GHG emissions, compliance with a GHG PAL generally assures that the environment remains protected from adverse air impacts resulting from changes a source undertakes in compliance with such a PAL, because emissions cannot exceed this pre-established level without further review. A PAL also provides an incentive for a source to minimize GHG emissions increases from future projects in order to stay under the PAL and avoid triggering major modification permitting requirements.

A. Setting the PAL Level

The procedures at 40 C.F.R 52.21(aa)(6) require that PAL levels be established by summing the baseline actual emissions (as defined in 40 C.F.R. 52.21(b)(48)) for each emissions unit at the source and then adding the significance level for the PAL pollutant.

When determining the baseline actual emissions for units at the facility, the owner or operator may choose any consecutive 24-month period that occurred within the 10-year period (5-year period for electric utility steam generating units) immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received. A different 24-month period may be used for each PAL pollutant. Baseline actual emissions for the PAL must include fugitive emissions and emissions from startups, shutdowns, and malfunctions,[5] but are adjusted downward for any periods of non-compliance during the 24-

[3] Notice was published in the Wednesday, August 29 edition of the Washington Examiner.
[4] Signed by Administrator Jackson on June 29, 2012, and published in the Federal Register on July 12, 2012 with an effective date of August 13, 2012 (77 FR 41051).
[5] 40 C.F.R. 52.21(b)(48)(i)(*a*) and (ii)(*a*)

month period.[6] Emissions units that were permanently shut down after the 24-month period are subtracted from the PAL, and emissions units that began actual construction after the 24-month period must add the full potential to emit (PTE) of the unit in lieu of baseline actual emissions.

B. Monitoring, Testing, Recordkeeping, and Reporting Requirements

Once the PAL level is determined for a PAL pollutant, the PAL permit includes monitoring, testing, recordkeeping, and reporting requirements in order to demonstrate compliance with the PAL level.

The owner or operator must show that the sum of the monthly emissions from each emissions unit for the previous 12-consecutive months is less than the PAL. In order to adequately demonstrate compliance, the PAL monitoring system, at a minimum, must use one of the four general monitoring approaches listed at 40 C.F.R. 52.21(aa)(12)(ii): 1) Mass balance calculations for activities using coatings or solvents; 2) Continuous Emissions Monitoring Systems (CEMS); 3) Continuous Parametric Monitoring Systems (CPMS) or Predictive Emissions Monitoring Systems (PEMS); or 4) Emissions factors. The owner or operator may also employ an alternative monitoring approach that meets 40 C.F.R. 52.21(aa)(12)(i)(*a*) if approved by the Administrator.

The PAL regulations at 40 C.F.R. 52.21(aa)(12)(iii) through (ix) provide further detail on the minimum requirements of the PAL monitoring system for each of the four methods described above. These provisions also require testing to validate emissions factors used for significant emissions units within 6 months of issuance of the PAL and re-validation of data used to establish the PAL pollutant once every 5 years.[7]

Additional recordkeeping and reporting requirements in the PAL provisions include the requirement for the owner or operator to maintain all records necessary to determine compliance with the PAL requirements for 5 years from the date of the record, including a copy of the PAL application and each annual title V compliance certification. The owner or operator must also submit semi-annual reports that include a list of all emissions units modified or adding during the preceding reporting period, a deviation report, and any results of a re-validation test or method within three months of completion.[8]

C. PAL Lifetime, Reopening, Renewal, and Expiration

Once a PAL is issued, it is valid for a ten year period, beginning on the effective date of the permit.[9] Reopening of the PAL permit must be done in accordance with 40 C.F.R. 52.21(aa)(8),

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[6] 40 C.F.R. 52.21(b)(48)(i)(*b*) and (ii)((*b*)
[7] 40 C.F.R 52.21(aa)(12)(vi)(*c*) and 40 C.F.R. 52.21(aa)(12)(ix)
[8] 40 C.F.R. 52.21(aa)(13) and (14)
[9] The effective date, in general, means the date of issuance of the PAL permit. Also, please note that the ten year lifespan of the PAL reflects the federal requirements under the PSD regulations (40 C.F.R. 52.21(aa)(2)(vii), PAL regulations for state and local permitting agencies may have a shorter PAL effective period.

as well as the public participation requirements of 40 C.F.R. 52.21(aa)(5),[10] with the exception of corrections of typographical/calculation errors that do not increase the PAL level.

In order to renew the PAL, the owner or operator must submit an application which includes the information an initial application for a PAL must contain (list of emissions units designated as small, significant, or major, baseline actual emissions, calculations for compliance purposes, etc.) as well as a new proposed PAL level, the sum of the PTE of all emissions units under the PAL, and supporting information. The application must be submitted at least six months prior to, but not earlier than 18 months from, the date of permit expiration.[11] If the permit is not renewed in accordance with procedures in 40 C.F.R. 52.21(aa)(10), the permit expires.

V. Capitol Power Plant PAL Level Calculations

This permitting action addresses emissions of PM_{10}, NO_2, and GHGs from the Capitol Power Plant through the use of PALs. This section provides a summary of how the PAL levels were set for each pollutant and the methods used to calculate baseline actual emissions for emissions units at the facility. Table 1 lists the existing emission units at the facility.

Table 1: Emissions Units and Size[12]

Emissions Unit	ID No.	PM_{10} Status	NO_x Status	GHG Status
Boiler 1	B1	Significant	Major	Major
Boiler 2	B2	Significant	Major	Major
Boiler 3	B3	Small	Major	Small
Boiler 4	B4	Small	Significant	Small
Boiler 5	B5	Small	Significant	Small
Boiler 6	B6	Small	Significant	Small
Boiler 7	B7	Small	Significant	Small
Ash Handling	N/A	Small	N/A	N/A
Coal Handling	N/A	Small	N/A	N/A
Cooling Towers	N/A	Significant	N/A	N/A
Miscellaneous Combustion Units (Engines)	N/A	Small	Small	Small

[10] 40 C.F.R. 52.21(aa)(5) references the public participation requirements of 40 C.F.R. 51.160 and 161, however, EPA relies on 40 C.F.R. 124 in issuing federal permits.
[11] 40 C.F.R. 52.21(aa)(10)(ii)
[12] Size of the respective emissions unit is based on PTE, and “small,” “significant,” and “major” means “small emissions unit,” “significant emissions unit,” and “major emissions unit” as defined in 40 C.F.R. 52.21(aa)(2)

A. Addressing PM_{10} Emissions with a PM_{10} PAL

The PAL for PM_{10} in the draft permit is set at 42.8 tons per year (TPY) and includes condensable particulate emissions. CPP chose a consecutive 24-month period from August 2004 until July 2006, which yielded baseline actual emissions of 27.8 TPY PM_{10}. The PAL level was derived by adding the significant emissions rate for PM_{10} (15 TPY) to the baseline actual emissions.

1. Boilers 1 through 7

CPP has seven boilers on site, ranging from 160 MMBtu/hr (Boilers 1 – 3) to 50 MMBtu/hr (Boiler 4-7). Boilers 1 and 2 are co-fired by coal and natural gas, and Boilers 3 to 7 are fired by natural gas and fuel oil. PM_{10} emissions from all seven boilers were based on AP-42 emissions factors for external combustion sources as indicated in Table 2.

Table 2: Emissions Factors for Boilers at CPP

	Filterable PM_{10}			Condensable PM_{10}		
Fuel	EF	Units	Source	EF	Units	Source
Coal	0.072	lb/ton	AP-42 Table 1.1-9	0.04	lb/MMBtu	AP-42 Table 1.1-5
Oil	1	lb/Mgal	AP-42 Table 1.3-6	1.3	lb/Mgal	AP-42 Table 1.3-2
Natural Gas	1.9	lb/MMscf	AP-42 Table 1.4-2	5.7	lb/MMscf	AP-42 Table 1.4-2

The emissions factors in Table 2 were converted to standard units of lb/MMBtu, where necessary. These converted emissions factors are reflected in CPP's emissions calculations spreadsheet. (See Appendix C, page 29 of the application.) PM_{10} emissions from the boilers were calculated using the following equation:

$$PM_{10} = Fuel\ usage \times EF \times HHV \times \frac{1}{2000}$$

Where:

PM_{10}	=	monthly emissions of PM_{10}	(tons/month)
Fuel usage	=	amount of fuel combusted	(tons, scf, or gallons/month)
EF	=	fuel specific emissions factor	(lb/MMBtu)
HHV	=	high heating value of fuel	(MMBtu/ton, scf, or gallon)

The HHVs for coal and fuel oil used in the baseline actual emissions calculations were taken from quarterly fuel sampling results submitted to DDOE, and the HHV of natural gas was based on a default value of 1023 Btu/scf.[13] Fuel consumption data was based on quarterly reports

[13] EPA views the Applicant's use of 1023 Btu/scf as a reasonable default heating value for natural gas during the baseline period, since the average natural gas heat content delivered to consumers in the District of Columbia

submitted by CPP to DDOE. The PM_{10} emissions calculations can be found in Appendix C, page 28 of the application.

2. Ash Handling

Emissions generated by the ash handling are controlled by a baghouse. PM_{10} emissions from ash handling were calculated using the following equations from AP-42 for Aggregate Handling and Storage Piles:[14]

$$PM_{10} = EF \times ash \times H \times N \times (100 - \eta) \times \frac{1}{2000}$$

Where:

PM_{10}	=	monthly emissions of PM_{10}	(tons/month)
EF	=	PM_{10} emissions factor	(lb/ton)
ash	=	ash throughput	(0.6 tons/hour)
H	=	monthly hours of operation	(hours/month)
N	=	number of transfers	(1, unitless)
η	=	baghouse control efficiency	(98%)

The PM_{10} emissions factor was calculated using the following equation:

$$EF = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where:

EF	=	PM_{10} emissions factor	(lb/ton)
k	=	particle size multiplier for PM_{10}	(0.35, unitless)
U	=	average wind speed	(9.4 miles/hr)
M	=	material moisture content	(27%)

The monthly hours of operation were calculated from the following equation:

$$H = \frac{Coal \times HHV}{HI}$$

from 2007 to 2010 was 1026 Btu/scf, with a high of 1035 Btu/scf and a low of 1014 Btu/scf. *See* United States Energy Information Administration Website: http://www.eia.gov/dnav/ng/hist/nga_epg0_vgth_sdc_btucfa.htm

[14] AP-42 Section 13.2.4

Where:

H	=	monthly hours of operation	(hours/month)
Coal	=	coal consumption	(tons/month)
HHV	=	coal higher heating value	(MMBtu/ton)
HI	=	rated heat input of Boilers 1 and 2	(160 MMBtu/hr)

The average wind speed, U, was based on the average wind speed over the last 45 years at Washington National Airport. Moisture content of the fly ash was based on the mean moisture content listed in Table 13.2.4-1. The HHV of the fuel was taken from quarterly fuel sampling results.

Based on the data provided in CPP's application, PM_{10} emissions from ash handling during the baseline period were insignificant, ranging from approximately 8.7 x 10^{-7} to 6 x 10^{-4} lbs/month. CPP's calculations for PM_{10} emissions from ash handling are in Appendix C, page 43 of the application.

3. Coal Handling

Coal handling emissions were calculated using the three general equations listed above for ash handling. The coal moisture content of 4.5% was based on AP-42, Table 13.2.4-1. The coal handling system has three transfer points. Particulate emissions from coal handling did not contribute significantly to the PM_{10} baseline, never exceeding 20 lbs in a given month. Emissions calculations from coal handling can be found in Appendix C, page 46 of the application.

4. Cooling Towers

CPP currently has two operational cooling towers at the facility, the West Cooling Tower and the West Expansion Cooling Tower. Only emissions from the West Cooling Tower were used in establishing the baseline actual emissions, and emissions for September and October 2004 (the first two months of the baseline period) are considered to be zero as no data are available for these two months.

Emissions from the West Expansion Cooling Tower were not included in the baseline actual emissions because the unit could not be classified as either an existing "emission unit" or a "newly constructed unit" under the PAL regulations. While *actual construction* of the West Expansion Cooling Tower began before the end of the 24-month baseline period used to establish the PM_{10} PAL, it was not *operational* until late 2006/early 2007, after the 24-month baseline period. Therefore, the West Expansion Cooling Tower was not considered either a "newly constructed unit", or an existing emissions unit. (see 40 C.F.R. 52.21(aa)(6)(i), which references 52.21(b)(48)). A third cooling tower, the East Refrigeration Plant Cooling Tower, is no longer in operation and emissions from the unit were not used in calculating the PAL level. PM_{10} emissions from the West Cooling Tower were calculated using historical data for water flow rate through the tower and test data for total dissolved solids (TDS). The daily chilled water flow rate for each tower was included in daily summary reports that were compiled on a weekly basis to calculate a weekly average flow rate. The TDS concentration was analyzed once per week. In the event that TDS information was missing or not available due to a monitoring equipment malfunction, information from adjacent weeks or the West Expansion Cooling Tower was used to calculate emissions.

Emissions from the cooling towers were calculated using TDS and flow rate information and AP-42 Section 13.4 – Wet Cooling Towers.

$$PM_{10} = EF \times L_{drift} \times 60 \times 24 \times 7$$

Where:

PM_{10}	=	weekly PM_{10} emissions	(lb/week)
EF	=	emissions factor	(lb/gal)
L_{drift}	=	drift loss	(gpm)
60 x 24 x 7	=	conversion of minutes to weeks	

The emissions factor, EF, for PM_{10} was calculated from the following equation:

$$EF = \frac{TDS \times 3.78}{453.6 \times 1000}$$

Where:

EF	=	emissions factor	(lb/gal)
TDS	=	TDS concentration	(ppm)
3.78	=	ppm to grams/gal conversion	
453.6	=	grams to pounds conversion	
1000	=	constant	(1000 gal/kgal)

L_{drift} was calculated as:

$$L_{drift} = \frac{CWFR \times L_{draft}}{1000 \times \rho_{H_2O}}$$

Where:

L_{drift}	=	drift loss	(gpm)
CWFR	=	circulating water flow rate	(gpm)
L_{draft}	=	draft loss factor	(lb/1000 gal)
ρ_{H_2O}	=	density of water	(8.345 lb/gal)
1000	=	constant	(1000 gal/kgal)

It was assumed that all particulate emissions from the cooling towers were $PM_{2.5}$, so the same emissions factor was used to calculate PM_{10} and $PM_{2.5}$ emissions. AP-42 Chapter 13.4 includes emissions factors for natural draft and induced draft towers. Since the fans for the towers are not operated at all times, CPP estimated a total draft loss factor based on the fans running 50 percent of the time. The yearly average PM_{10} emissions from the West Cooling Tower were calculated to be 8.4 TPY, with the highest monthly emissions of 1.59 tons occurring in July 2006. Emissions calculations for the cooling towers can be found in Appendix C, page 34 of the application.

5. Miscellaneous Combustion Units

CPP has several small sources of PM_{10} located at the facility: one diesel-fired emergency generator (6.58 MMBtu/hr); one diesel-fired emergency fire pump (2.1 MMBtu/hr); one diesel-fired air compressor (0.74 MMBtu/hr); two diesel-fired portable generators (0.25 MMBtu/hr); and fuel oil-fired coal car burners (0.04 MMBtu/hr). Due to the size and the lack of historical data available, emissions from these units were not quantified or included in establishing baseline actual emissions; however, CPP will be required to calculate and report emissions from these units for compliance with the PM_{10} PAL.

6. Summary of Emissions Used to Establish PM_{10} PAL

Table 3: Emission Totals Used to Establish PM_{10} PAL

	PM_{10} Emissions (TPY)
Boilers 1-7	19.4
Ash Handling	0
Coal Handling	0
Cooling Tower	8.4
Misc. Combustion Equipment	0
PM_{10} Significant Emissions Rate	15
PM_{10} PAL Level	**42.8**

B. Addressing NO_2 Emissions with a NO_x PAL

Based on its review of the air quality criteria for oxides of nitrogen and the primary national ambient air quality standard (NAAQS) for oxides of nitrogen (NO_x) as measured by nitrogen dioxide (NO_2), EPA revised the primary NO_2 NAAQS on January 22, 2010 in order to provide requisite protection of public health. EPA policy provides that any federal PSD permit issued under 40 CFR 52.21 on or after that effective date must contain a demonstration of source compliance with the new standard.

The new standard, which is expressed in 40 C.F.R. 50.11 as the ambient air quality standard for oxides of nitrogen, retains NO_2 as the indicator for the standard. Therefore, when we refer to ambient concentrations for the purposes of the NAAQS, the reference is generally to NO_2.

However, emissions have traditionally been regulated for the NO_2 standard as NO_x. For example, the definition of "significant" in 40 C.F.R. 51.165(a)(1)(x), 51.166(b)(23) and 52.21(b)(23) establishes a level where NO_x emissions alone are significant, and then separately for when they are significant for NO_x as a precursor to ozone and once more for NO_x as a precursor to $PM_{2.5}$. On this basis, CPP requested a PAL for NO_2, to distinguish between NO_x as a PSD pollutant for which the area is attaining the standard, and NO_x as a nonattainment pollutant as a precursor for the ozone and $PM_{2.5}$ NAAQS. Therefore, to address NO_2 emissions, the PAL established in this permitting action is expressed as a NO_x emissions limit that is intended to be protective of the ambient standard for nitrogen oxides for which NO_2 is the indicator. Since NO_x refers to a family of nitrogen and oxygen compounds that includes NO_2, regulating NO_2 emissions through the use of a NO_x PAL will assure compliance with the NAAQS.

The PAL for NO_x in the draft permit is set at 248.1 TPY. Baseline actual emissions for the 24-month period from November 2002 until October 2004 chosen by CPP were 208.1 TPY NO_x. The PAL level is set at the baseline actual emissions plus the 40 tpy significant level for NO_x. The ash handling, coal handling, and cooling towers are not sources of NO_x emissions, and as a result were not part of setting the PAL level for NO_x.

Miscellaneous combustion equipment was also not included in the baseline actual emissions due to the small size of the equipment and lack of historical data;[15] however, CPP will be required to quantify NO_x emissions from these units in order to demonstrate compliance with the PAL.

1. Boilers 1 through 7

NO_x CEMS are installed on the east and west stacks at CPP. Emissions from Boilers 1 and 2 exit the east stack, and emissions from Boilers 3 to 7 exit the west stack. NO_x emissions from each of the boilers at CPP were calculated using emissions factors derived from CEMS data, fuel use records, and high heating values (HHVs) of the fuel. Coal and fuel oil are sampled on a quarterly basis; natural gas was assumed to have a HHV of 1023 Btu/scf.

Boiler 3 was out of compliance with a 10 TPY NO_x limit during the baseline period. Baseline actual emissions for this boiler were adjusted downward to the permit limit to compensate for the non-compliance[16]. The significant emissions rate for NO_x (40 TPY) was added to set the PAL level at 248.1

[15] See discussion in V.A.5

[16] 40 C.F.R. 52.21(b)(48)(ii)(*b*)

2. Summary of Emissions Used to Establish NO_x PAL

Table 3: Emission Totals Used to Establish NO_x PAL

	NO_x Emissions (TPY)
Boiler 1	94.6
Boiler 2	88.5
Boiler 3	10*
Boiler 4	4.9
Boiler 5	4.2
Boiler 6	2.8
Boiler 7	3.1
NO_x Significant Emissions Rate	40
NO_x PAL Level	**248.1**

* Baseline actual emissions adjusted downward for periods of noncompliance.

C. Addressing GHG Emissions through a CO_2e-based PAL

The PAL for GHGs in the draft permit is set at 203,816 TPY CO_2e. Baseline actual emissions for GHGs were 128,816 TPY CO_2e for the 24-month period from November 2002 until October 2004. The PAL level was set at the threshold where GHGs become subject to regulation for an existing major stationary source under the current regulations, i.e., at 75,000 TPY CO_2e above baseline actual emissions. CPP included carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) in its emissions calculations for GHGs. The three other GHG pollutants (hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) are not emitted from the existing emission units at the facility, and thus were not considered in estimating the GHG emissions from CPP.

The ash handling, coal handling, and cooling towers do not emit GHGs.

Miscellaneous combustion equipment was not included in baseline actual emissions due to the small size of the equipment and lack of historical data; however, CPP will be required to quantify CO_2e emissions from these units in order to demonstrate compliance with the PAL.

1. Boilers 1 through 7

Baseline actual GHG emissions were calculated for Boilers 1 through 7 as CO_2e using historical fuel use data, emissions factors from Tables C-1 and C-2 of 40 C.F.R. 98 Subpart C, "General Stationary Fuel Combustion Sources," and listed global warming potentials (GWP) of the GHGs.

An emissions factor for CO_2e was calculated for coal, natural gas, and fuel oil on a fuel specific basis using the emissions factors and GWP for each individual GHG pollutant emitted from the boilers:

$$EF_{CO_2e} = \left(EF_{CO_2} \times GWP_{CO_2}\right) + \left(EF_{CH_4} \times GWP_{CH_4}\right) + \left(EF_{N_2O} \times GWP_{N_2O}\right)$$

Where:

EF_{CO2e}	=	CO_2e emissions factor	(kg/MMBtu)
EF_{CO2}	=	CO_2 emissions factor	(kg/MMBtu)
GWP_{CO2}	=	GWP for CO_2	(1, dimensionless)
EF_{CH4}	=	CH_4 emissions factor	(kg/MMBtu)
GWP_{CH4}	=	GWP for CH_4	(21, dimensionless)
EF_{N2O}	=	N_2O emissions factor	(kg/MMBtu)
GWP_{N2O}	=	GWP for N_2O	(310, dimensionless)

Fuel specific emissions factors used to develop a CO_2e emissions factor for each fuel are as follows:

Table 4: Fuel Specific Emissions Factors for GHGs

Pollutant	Coal	Oil	Gas	Units
CO_2	93.4	73.96	53.02	kg/MMBtu
CH_4	1.10E-02	3.00E-03	1.00E-03	kg/MMBtu
N_2O	1.60E-03	6.00E-04	1.00E-04	kg/MMBtu

After converting kilograms to pounds, the following emissions factors were calculated for each fuel:

Coal	=	207.51 lb CO_2e /MMBtu
Natural gas	=	117 lb CO_2e /MMBtu
Fuel Oil	=	163.60 lb CO_2e /MMBtu

CPP was able to calculate GHG emissions over the baseline period using fuel use records, the measured heating value of the fuel for coal and fuel oil from quarterly sampling, and an assumed high heating value of 1023 Btu/scf for natural gas.

2. Summary of Emissions Used to Establish GHG PAL on a CO_2e Basis

Table 5: Emission Totals Used to Establish GHG PAL

	GHG Emissions (TPY CO_2e)
Boiler 1	46906
Boiler 2	45317
Boiler 3	18677.5

Boiler 4	5168
Boiler 5	5090
Boiler 6	3679.5
Boiler 7	3977.5
GHG "Subject to Regulation" Threshold	75000
GHG PAL Level	**203816**

VI. Monitoring Requirements

Upon issuance of the PAL, CPP must be able to demonstrate compliance with the PM_{10}, NO_x, and GHG TPY limits. For each month during the first 11 months from the PAL effective date, CPP shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.[17] The PAL permit also must include the calculation procedures that CPP must use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total.[18] This section provides a detailed discussion on the calculation methods included in the PAL permit that CPP is required to use to demonstrate compliance with the PALs.

A. Boilers 1 through 7

Boilers 1 and 2 are identical 160 MMBtu/hr Wickes boilers and are fired by coal and natural gas. Boilers 3 through 7 consist of one 160 MMBtu/hr Wickes boiler and four 50 MMBtu/hr Erie City Iron Works boilers, and are fired by fuel oil or natural gas. Emissions calculation methods for PM_{10}, NO_x, and GHGs for these units in order to demonstrate compliance with the PALs are described below.

1. PM_{10} Monitoring

CPP is required to monitor the fuel throughput for Boilers 1 through 7 on a continuous basis. PM_{10} emissions from Boilers 1 and 2 will be calculated monthly using the following equations:

For coal:

$$PM_{10}\left(\frac{tons}{month}\right) = 0.072\left(\frac{lb\ PM_{filterable}}{ton}\right) \times coal\ throughput\ \left(\frac{tons\ coal}{month}\right) \times \frac{1\ ton}{2000\ lbs}$$

$$+ 0.04\left(\frac{lb\ PM_{cond.}}{MMBtu}\right) \times HHV_{coal}\left(\frac{MMBtu}{ton}\right) \times\ coal\ throughput\ \left(\frac{tons\ coal}{month}\right) \times \frac{1\ ton}{2000\ lbs}$$

[17] See 40 C.F.R. 52.21(aa)(4)(i)(*a*)
[18] See 40 C.F.R. 52.21(aa)(7)(vi)

The first half of the equation reflects the emissions of filterable PM_{10} using an emissions factor of 0.072 lb PM_{10}/ton, and the second half accounts for condensable PM_{10} using an emissions factor of 0.04 lb PM_{10}/MMBtu.

For natural gas:

$$PM_{10}\left(\frac{tons}{month}\right) = 7.6\left(\frac{lbs\ PM_{10}}{MMscf}\right) \times natural\ gas\ throughput\left(\frac{MMscf}{month}\right) \times \frac{1\ ton}{2000\ lbs}$$

The emissions factor of 7.6 lbs PM_{10}/MMscf was derived from combining AP-42 emissions factors for natural gas combustion for filterable PM_{10} (5.7 lb/MMscf) and condensable PM_{10} (1.9 lb/MMscf).

Boilers 1 and 2 have been identified by CPP as being "significant emissions units" for PM_{10}. 40 C.F.R. 52.21(aa)(12)(vi)(*c*) states:

> "If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the Administrator determines that testing is not required."

EPA is requiring that CPP conduct stack tests for PM_{10} emissions, including condensables, on these units in order to develop a site specific emissions factor. CPP shall use the emissions factors in the equations above to demonstrate compliance with the PM_{10} PAL unless or until a site specific emissions factor is developed. Since the emissions factors used to calculate baseline actual emissions are the same ones CPP is using to demonstrate compliance, EPA may require adjustment of the PAL level depending on the results of further testing.[19]

PM_{10} emissions (including condensables) for Boilers 3 through 7 will be calculated on a monthly basis using similar methods as Boilers 1 and 2, and using an emissions factor of 7.6 lb PM_{10}/MMscf for natural gas combustion. When firing fuel oil, PM_{10} emissions will be calculated using an emissions factor of 2.3 lbs PM_{10}/ 1000 gallons (Mgal). This emissions factor was derived by adding the fuel oil emissions factors for filterable PM_{10} (1 lb/Mgal) and the condensable fraction (1.3 lb/Mgal).

Boilers 3 through 7 were not listed as significant emissions units for PM_{10} by CPP, and will not be required to perform validation testing (40 C.F.R. 52.21(aa)(12)(vi)(*c*)).

2. NO_x Monitoring

CPP is using a NO_x CEMS to calculate NO_x emissions from the boilers. CEMS for Boilers 1 and 2 are located on the East Stack and CEMS for Boilers 3 through 7 are on the West Stack. The

[19] See 40 C.F.R. 52.21(aa)(8)(ii)(*a*)(1)

CEMS must comply with applicable Performance Specifications found in 40 C.F.R. part 60, Appendix B and sample, analyze and record data at least every 15 minutes while the emissions unit is operating.[20] The PAL permit is also requiring that the CEMS comply with all applicable requirements of 40 C.F.R. 60.13.

3. GHG (CO2e) Monitoring

CPP is required to monitor the fuel throughput for the boilers on a continuous basis. CO_2, CH_4, and N_2O emissions from each of the boilers will be calculated monthly using the following equation and emissions factors listed in Table 4 of this Fact Sheet:

$$CO_2 or\ CH_4\ or\ N_2O\ emissions = \ Fuel\ throughput\ \times HHV\ \times EF \times \frac{2.2046}{2000}$$

The heating value for coal or fuel oil will be from the most recent quarterly sample, and natural gas will have a default HHV of 1020 Btu/scf.

The resultant emissions for each GHG pollutant listed above will be multiplied by their global warming potential and summed to calculate CO_2e emissions for any given month:

$$\mathrm{CO_2e} = \mathrm{CO_2} \times 1 + \mathrm{CH_4} \times 21 + \mathrm{N_2O} \times 310$$

Boilers 1 and 2 have been identified by CPP as being "significant emissions units" for GHGs. In accordance with 40 C.F.R. 52.21(aa)(12)(vi)(*c*), EPA is requiring that CPP conduct stack tests for CO_2 on these units in order to develop a site specific emissions factor for CO_2. CPP shall use the emissions factors in the equations above to demonstrate compliance with the CO_2e PAL unless or until a site specific emissions factor is developed. Since the emissions factors used to calculate baseline actual emissions are the same ones CPP is using to demonstrate compliance, EPA may require adjustment of the PAL level depending on the results of the stack tests.[21]

CO_2 emissions account for over 99% of CO_2e emissions from Boilers 1 and 2 for both coal and natural gas combustion. Since emissions of N_2O and CH_4 are such an insignificant component of the GHGs emitted from the boilers, EPA is not requiring CPP to test and develop site specific emissions factors for these pollutants. Nevertheless, CPP is still required to account for emissions of N_2O and CH_4 in their CO_2e calculations using the emissions factors in Table 4.

B. Ash Handling, Coal Handling, and Cooling Tower Monitoring

[20] 40 C.F.R. 52.21(aa)(iv)(*a*) and (*b*)
[21] See 40 C.F.R. 52.21(aa)(8)(ii)(*a*)(1)

The draft PAL permit requires CPP to monitor coal throughput in Boilers 1 and 2 once per month as well as the amount of coal delivered for each coal delivery. Using this data and the HHV from quarterly coal sampling, emissions from the ash handling and coal handling will be calculated for compliance with the PM_{10} limit in the same way that baseline actual emissions from these units were calculated.[22]

CPP will also be required to monitor the water flow rate through the cooling towers (for each cooling tower), the TDS concentration, and hours of operation on a weekly basis. Monthly PM_{10} emissions from the cooling towers will be calculated by combining the equations in Section V.A.4:

$$PM_{10} = \frac{TDS \times 3.78 \times CWFR \times L_{draft} \times T \times 60}{453.6 \times 10^6 \times \rho_{H2O}}$$

Where:

PM_{10}	=	Monthly emissions of PM_{10}	(tons)
TDS	=	Total dissolved solids concentration	(ppm)
CWFR	=	Circulating water flow rate	(gpm)
L_{draft}	=	Draft loss factor (0.8865)	(lb/1,000 gal)
T	=	Time, monthly hours of operation	(hours)
P_{H2O}	=	Density of water (8.345)	(lb/gal)

C. Miscellaneous Combustion Unit Monitoring

As stated previously in the Fact Sheet, CPP has several small combustion units at the facility, including coal car burners, an air compressor, an emergency fire pump, and an emergency generator. The draft PAL permit requires that CPP continuously monitor the hours of operation on the miscellaneous combustion units through the use of an hour meter. Monthly emissions from these units will be calculated using hours of operation in a given month and the following information:

[22] See Section V.A.2 and 3 of this Fact Sheet

Table 6: Miscellaneous Combustion Unit Emissions Calculation Data

	Fuel Consumption Rate (gal/hr)	PM_{10}	NO_x	GHGs		
				CO_2	N_2O	CH_4
Coal Car Burners	54	3.3 lb/ 1000 gal oil	20 lb/ 1,000 gal oil	73.96 kg/MMBtu	6.0x10-4 kg/MMBtu	3.0x10-3 kg/MMBtu
Air Compressor	5.3	0.31 lb/ MMBtu	4.41 lb/ MMBtu			
Emergency Fire Pump	15	5.07e-4 lb/ hp-hr	0.01 lb/ hp-hr			
Emergency Generator	104	0.0573 lb/ MMBtu	3.2 lb/ MMBtu			

Fuel consumption rates in the table above were either supplied by the manufacturer or calculated using the rating of the emissions unit and the HHV of the fuel, which was assumed to be 140,000 Btu/gal.[23]

D. Emissions Units Added After the PAL

In order to accurately calculate plantwide emissions at the facility, any new or modified emissions units must also have associated monitoring that meets one of the four general monitoring approaches listed in 40 C.F.R. 52.21(aa)(12) and Subsection 4.c of the PAL permit. In order to assure that these monitoring requirements are being met, CPP must submit semi-annual reports to EPA that list any new or modified emissions units since submittal of the last report. These reports must identify which of the four general monitoring approaches are being used to calculate emissions, and must include emissions factors, fuel use data, manufacturer's specification, or any other information that is or will be used to account for emissions from the new or modified units. Failure to use a monitoring system that meets the requirements of 40 C.F.R. 52.21(aa)(12) renders the PAL invalid.[24]

Facilities with a PAL must still comply with all federal and District requirements. DDOE's NSR program in Chapter 20, Title 2 of the District of Columbia Municipal Regulations imposes requirements for both minor and major NSR. Permits issued under these regulations are referred to as a "Chapter 2 permits." CPP must still apply for a Chapter 2 permit for new units or to modify existing units to the extent required by the District's regulations.

[23] See July 20, 2012 memorandum from Ian Donaldson, Trinity Consultants, to Mike Gordon, U.S. EPA, Re: Conversion Factors for PAL Permits
[24] See 40 C.F.R. 52.21(aa)(12)(i)(*d*)

VII. Testing Requirements

Boilers 1 and 2 are significant emissions units for PM_{10} and GHGs under the PAL regulations and CPP will be required to conduct stack testing for PM_{10} (including condensables) and CO_2. Methods 201A and 202 will be used to test for filterable PM_{10} and condensable particulate matter, respectively. Method 3B in 40 C.F.R. 60, Appendix A-2 will be used for CO_2 emissions. The results of the tests may be used to develop site specific emissions factors in accordance with 40 C.F.R. 52.21(aa)(12)(vi)(*c*). As discussed in Section VI.A.1, EPA may adjust baseline actual emissions and the corresponding PAL as well as the emissions factors used to demonstrate compliance with the PAL in order to more accurately reflect emissions from these units. Testing must be performed within 6 months of the effective date of the PAL, and results of the stack test, including the site specific emissions factors, must be submitted to EPA within 60 days of testing.

VIII. Federal Consultations

A. National Historic Preservation Act

Under Section 107 of the National Historic Preservation Act (NHPA), *16 U.S.C. 470g*:

> Nothing in this Act shall be construed to be applicable to the White House and its grounds, the Supreme Court building and its grounds, or the United States Capitol and its related buildings and grounds.

Therefore, no NHPA consultation is necessary for this permitting action.

B. Endangered Species Act

Pursuant to section 7 of the ESA, 16 U.S.C. § 1536, and its implementing regulations at 50 C.F.R. Part 402, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA has determined that this permitting action is not subject to ESA section 7 requirements.

On May 29, 2012, EPA submitted an endangered species and critical habitat list review on behalf of Mr. Brian Klein, Architect of the Capitol, to the Fish and Wildlife Service (FWS).[25] In a June 13, 2012 letter[26] to Mr. Klein, FWS responded in part that:

> "Except for occasional transient individuals, no proposed or federally listed endangered or threatened species are known to exist within the project impact area. Therefore, no Biological Assessment or further section 7 consultation with the U.S. Fish and Wildlife Service is required."

[25] See Endangered Species List Review.docx, included in the docket
[26] See letter from Ms. Genevieve LaRouche, FWS, to Mr. Brian Klein, Architect of the Capitol

Therefore, no further Biological Assessment or section 7 consultation was done as part of this permitting action.

IX. Environmental Justice

Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," states in relevant part that "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." Section 1-101 of Exec. Order 12898, 59 Fed. Reg. 7629 (Feb. 16, 1994). Working for environmental justice is one of our top priorities at EPA, and the Agency recently issued a plan that will enable us to better integrate environmental justice and civil rights into our programs, policies and daily work, including our permitting actions (see Plan EJ 2014, published September 2001, at pages 10-12 and 41-55).

With regard to emissions of GHGs authorized by this permitting action, EPA notes that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no NAAQS for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis of the GHG emissions allowed under this permit is not necessary for the permitting record.

With regard to emissions of PM_{10} and NO_2 (as addressed through a NO_x PAL) authorized by this permitting action, EPA has also determined that this permitting action will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations, because it does not affect the level of CAA protection provided to human health or the environment. This permitting action ensures that emissions of PM_{10} and NO_2 from the CPP will not impact continued compliance with applicable NAAQS. NAAQS are national health-based standards that have been set at a level such that their attainment and maintenance will protect public health and welfare, including sensitive individuals, with an adequate margin of safety. See CAA § 109(b). Numerous health studies and comments from experts and the public are used in determining the NAAQS level that will be protective of public health.
EPA notes that the PALs established in this permit require that total emissions may only increase in amounts below the NSR significant emission levels. Those significant emission thresholds have been set at a level that represents de minimis emission increases that EPA has determined

not to affect compliance with the NAAQS. Since the emission limits in the permit are set such that only de minimis increases in emissions may occur, this permitting action will protect air quality in the region by ensuring compliance with the applicable NAAQS.[27]

EPA has gathered demographic information regarding the community surrounding CPP.[28] EPA has not identified anything about the demographic information for this community that would cause us to question the protectiveness of the NAAQS and the significant emission levels for this population in this permit. Since the PALs established in this permit are set at a level based on past operation and allow only de minimis emissions increases that are protective of the NAAQS, EPA has determined that this permitting action will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations.

X. Conclusion

EPA is proposing to issue a PAL permit for the CPP. We believe that the proposed action will comply with the requirements at 40 C.F.R. 52.21(aa). We have made this determination based on the information supplied by the applicant and our review of the analyses contained in the permit application and other relevant information contained in our administrative record. EPA will make this proposed permit and this Fact Sheet available to the public for review, and make a final decision after considering any public comments on our proposal.

[27] To the extent that that the PSD attainment pollutants addressed by the PALs in this permitting action are also a subset of pollutants for which the region is not in attainment (such as NO_2 is a subset of NO_x, which are a precursor for ozone and $PM_{2.5}$), we note that CPP is also applying to the District for a nonattainment NSR (nNSR) permit to address those pollutants, which will contain limits set at a level to ensure that the CPP will not have any additional impact on the NAAQS. Accordingly, the emissions from CCP as a result of this permitting action and the resulting nNSR permitting action will not have any adverse impact on the NAAQS, much less a disproportionately high and adverse impact on human health or the environment for minority or low-income populations.

[28] See the link to Environmental Justice Screening Assessment and 2010 Demographics documents for this permitting action at http://www.epa.gov/reg3artd/.