DEPARTMENT OF THE ENVIRONMENT
Air and Radiation Management Administration
1800 Washington Boulevard, Suite 720
Baltimore, MD 21230

☐ Construction Permit
☐ Operating Permit

PERMIT NO. 24-031-0019

To be paid in accordance with COMAR 26.11.02.19B(b)

DATE ISSUED November 1, 2015

PERMIT FEE

EXPIRATION DATE October 31, 2020

LEGAL OWNER & ADDRESS
NRG Energy Inc.
21200 Martinsburg Road
Dickerson, MD 20842
Attn: David M. Bennett, Plant Manager

SITE
GenOn Dickerson Generating Station
21200 Martinsburg Road
Dickerson, MD 20842
Montgomery County
Al # 46

SOURCE DESCRIPTION
Coal Fired Power Electric Generating Station.

This source is subject to the conditions described on the attached pages.

Page 1 of 140

Program Manager

Director, Air and Radiation Management Administration

(TRANSCIBERABLE)
12. GENERAL RECORDKEEPING ................................................................. 32
13. GENERAL CONFORMITY .................................................................. 33
14. ASBESTOS PROVISIONS ................................................................. 33
15. OZONE DEPLETING REGULATIONS ................................................ 33
16. ACID RAIN PERMIT ...................................................................... 34

SECTION IV  PLANT SPECIFIC CONDITIONS ................................. 35

SECTION V  INSIGNIFICANT ACTIVITIES ......................................... 123

SECTION VI  STATE-ONLY ENFORCEABLE CONDITIONS ................ 127

APPENDIX A  ACID RAIN PERMIT

ATTACHMENT: CO₂ BUDGET AND TRADING PROGRAM PERMIT
SECTION I SOURCE IDENTIFICATION

1. DESCRIPTION OF FACILITY

The Dickerson Generating Station is engaged in the generation of electric energy for sale. The primary SIC code for this facility is 4911. The major components of the facility consist of three (3) steam units primarily firing bituminous coal, an oil fired combustion turbine primarily used for black start and peaking service, and two (2) peaking service combustion turbines primarily firing natural gas located on site at Station H.

Each of the three (3) boilers, manufactured by Combustion Engineering, Inc. (Alstom) is rated at 191 megawatts. The boilers are tangentially coal fired, with a superheater, re heater and economizer. Each boiler is equipped with its own Electrostatic Precipitator (ESP) and Selective Non-Catalytic Reduction (SNCR) system. In addition there is a common baghouse and Flue Gas Desulfurization (FGD) system for all three units. When the FGD is in operation all three units exhaust through a common 400 foot high wet stack. When the FGD is not in operation all three units exhaust through a common 700 foot high dry stack.

The single black start combustion turbine (CT), manufactured by Pratt & Whitney is used both for black start capability and peaking service. The combustion turbine is No. 2 oil fired and rated at 18 megawatts.

The two (2) combustion turbines manufactured by General Electric are used for peaking capacity. Each is rated at 167 megawatts and fires primarily natural gas with No. 2 fuel oil as secondary fuel, and each have a nominal capacity of 167 megawatts. Each combustion turbine units emissions exhaust through a 213-foot stack.

2. FACILITY INVENTORY LIST

<table>
<thead>
<tr>
<th>Emissions Unit Number</th>
<th>MDE Registration Number</th>
<th>Emissions Unit Name and Description</th>
<th>Date of Installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>D-1</td>
<td>3-0001</td>
<td>One (1) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boiler nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boiler unit is equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system.</td>
<td>June 1959</td>
</tr>
<tr>
<td>Emissions Unit Number</td>
<td>MDE Registration Number</td>
<td>Emissions Unit Name and Description</td>
<td>Date of Installation</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-------------------------</td>
<td>------------------------------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>D-2</td>
<td>3-0002</td>
<td>FGD system.</td>
<td>April 1960</td>
</tr>
<tr>
<td></td>
<td></td>
<td>One (1) Combustion Engineering, Inc</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>tangentially fired, dry bottom, drum,</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>bituminous coal fired boiler nominally rated at 191 megawatts.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>No. 2 fuel oil is used for ignition, warm-up and flame stabilization.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>The boiler unit is equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system.</td>
<td></td>
</tr>
<tr>
<td>D-3</td>
<td>3-0003</td>
<td>One (1) Combustion Engineering, Inc</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>tangentially fired, dry bottom, drum,</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>bituminous coal fired boiler nominally rated at 191 megawatts.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>No. 2 fuel oil is used for ignition, warm-up and flame stabilization.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>The boiler unit is equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system.</td>
<td>March 1962</td>
</tr>
<tr>
<td>D CT-1</td>
<td>4-0907</td>
<td>One (1) Pratt and Whitney FT4-A</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>combustion turbine rated at 18 megawatts, fires No.2 fuel oil and utilized for black start and peaking service.</td>
<td>March 1967</td>
</tr>
<tr>
<td>H CT-1</td>
<td>9-0362</td>
<td>One (1) General Electric Frame 7F</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>combustion turbine with a nominal rated capacity of 167 megawatts located at Station H. The combustion turbine fires primarily natural gas and No. 2 fuel oil as a secondary fuel. The unit is equipped with inlet foggers to maintain output at high ambient temperatures and with water injection to control NO\textsubscript{X} emissions.</td>
<td>June 1992</td>
</tr>
<tr>
<td>H CT-2</td>
<td>9-0363</td>
<td>One (1) General Electric Frame 7F</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>combustion turbine with a nominal rated capacity of 167 megawatts located at Station H. The combustion turbine fires primarily natural gas and No. 2 fuel oil as a secondary fuel. The unit is equipped with inlet foggers to maintain output at high ambient temperatures and with water injection to control NO\textsubscript{X} emissions.</td>
<td>June 1993</td>
</tr>
<tr>
<td>Emissions Unit Number</td>
<td>MDE Registration Number</td>
<td>Emissions Unit Name and Description</td>
<td>Date of Installation</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-------------------------</td>
<td>------------------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td>Ash and coal handling operations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FGD System</td>
<td>CPCN 9087</td>
<td>A common wet flue gas desulfurization (FGD) system is installed on Units 1-3. The FGD system controls SO₂ and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing gypsum as a by-product. The FGD system consists of the following sub-systems: limestone unloading and storage facilities; limestone slurry preparation and feed; SO₂ absorption tower; gypsum dewatering and loading facilities and two emergency diesel engines.</td>
<td>December 2009</td>
</tr>
<tr>
<td>SNCR System</td>
<td>CPCN 9140</td>
<td>Unit 1-3 have Selective Non-Catalytic Reduction systems installed, consisting of urea injectors on the boilers and associated ancillary equipment</td>
<td>May 2009</td>
</tr>
</tbody>
</table>
SECTION II  GENERAL CONDITIONS

1.  DEFINITIONS

[COMAR 26.11.01.01] and [COMAR 26.11.02.01]

The words or terms in this Part 70 permit shall have the meanings established under COMAR 26.11.01 and .02 unless otherwise stated in this permit.

2.  ACRONYMS

APC  Air Pollution Control
ARMA  Air and Radiation Management Administration
BACT  Best Available Control Technology
Btu  British thermal unit
CAA  Clean Air Act
CAM  Compliance Assurance Monitoring
CEM  Continuous Emissions Monitor
CFR  Code of Federal Regulations
CO  Carbon Monoxide
COMAR  Code of Maryland Regulations
EPA  United States Environmental Protection Agency
ESP  Electrostatic Precipitator
FGD  Flue Gas Desulfurization
FR  Federal Register
gr  grains
HAP  Hazardous Air Pollutant
LNB  Low NOx Burner system
MACT  Maximum Achievable Control Technology
MDE  Maryland Department of the Environment
MVAC  Motor Vehicle Air Conditioner
NESHAPS  National Emission Standards for Hazardous Air Pollutants
NOx  Nitrogen Oxides
NSPS  New Source Performance Standards
NSR  New Source Review
OTR  Ozone Transport Region
PEM  Particulate Matter Emissions Monitor
PM  Particulate Matter
PM10  Particulate Matter with Nominal Aerodynamic Diameter of 10 micrometers or less
ppm  parts per million
ppb  parts per billion
NRG Energy, Inc  
Dickerson Generating Station  
21200 Martinsburg Road, Dickerson, Maryland 20842  
Part 70 Operating Permit No. 24-031-0019

PSD  Prevention of Significant Deterioration  
PTC  Permit to construct  
PTO  Permit to operate (State)  
SIC  Standard Industrial Classification  
SO$_2$  Sulfur Dioxide  
SOFA  Separate Over-Fired Air system  
TAP  Toxic Air Pollutant  
tpy  tons per year  
VE  Visible Emissions  
VOC  Volatile Organic Compounds  
WCF  Waste Combustible Fluid

3. EFFECTIVE DATE

The effective date of the conditions in this Part 70 permit is the date of permit issuance, unless otherwise stated in the permit.

4. PERMIT EXPIRATION

[COMAR 26.11.03.13B(2)]

Upon expiration of this permit, the terms of the permit will automatically continue to remain in effect until a new Part 70 permit is issued for this facility, provided that the Permittee has submitted a timely and complete application and has paid applicable fees under COMAR 26.11.02.16.

Otherwise, upon expiration of this permit the right of the Permittee to operate this facility is terminated.

5. PERMIT RENEWAL

[COMAR 26.11.03.02B(3)] and [COMAR 26.11.03.02E]

The Permittee shall submit to the Department a completed application for renewal of this Part 70 permit at least 12 months before the expiration of the permit. Upon submitting a completed application, the Permittee may continue to operate this facility pending final action by the Department on the renewal.

The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall
submit such supplementary facts or corrected information no later than 10 days after becoming aware that this occurred. The Permittee shall also provide additional information as necessary to address any requirements that become applicable to the facility after the date a completed application was submitted, but prior to the release of a draft permit. This information shall be submitted to the Department no later than 20 days after a new requirement has been adopted.

6. CONFIDENTIAL INFORMATION

[COMAR 26.11.02.02G]

In accordance with the provisions of the State Government Article, Sec. 10-611 et seq., Annotated Code of Maryland, all information submitted in an application shall be considered part of the public record and available for inspection and copying, unless the Permittee claims that the information is confidential when it is submitted to the Department. At the time of the request for inspection or copying, the Department will make a determination with regard to the confidentiality of the information. The Permittee, when requesting confidentiality, shall identify the information in a manner specified by the Department and, when requested by the Department, promptly provide specific reasons supporting the claim of confidentiality. Information submitted to the Department without a request that the information be deemed confidential may be made available to the public. Subject to approval of the Department, the Permittee may provide a summary of confidential information that is suitable for public review. The content of this Part 70 permit is not subject to confidential treatment.

7. PERMIT ACTIONS

[COMAR 26.11.03.06E(3)] and [COMAR 26.11.03.20(A)]

This Part 70 permit may be revoked or reopened and revised for cause. The filing of an application by the Permittee for a permit revision or renewal; or a notification of termination, planned changes or anticipated noncompliance by the facility, does not stay a term or condition of this permit.

The Department shall reopen and revise, or revoke the Permittee’s Part 70 permit under the following circumstances:
a. Additional requirements of the Clean Air Act become applicable to this facility and the remaining permit term is 3 years or more;

b. The Department or the EPA determines that this Part 70 permit contains a material mistake, or is based on false or inaccurate information supplied by or on behalf of the Permittee;

c. The Department or the EPA determines that this Part 70 permit must be revised or revoked to assure compliance with applicable requirements of the Clean Air Act; or

d. Additional requirements become applicable to an affected source under the Federal Acid Rain Program.

8. PERMIT AVAILABILITY

[COMAR 26.11.02.13G]

The Permittee shall maintain this Part 70 permit in the vicinity of the facility for which it was issued, unless it is not practical to do so, and make this permit immediately available to officials of the Department upon request.

9. REOPENING THE PART 70 PERMIT FOR CAUSE BY THE EPA

[COMAR 26.11.03.20B]

The EPA may terminate, modify, or revoke and reissue a permit for cause as prescribed in 40 CFR §70.7(g)

10. TRANSFER OF PERMIT

[COMAR 26.11.02.02E]

The Permittee shall not transfer this Part 70 permit except as provided in COMAR 26.11.03.15.
11. REVISION OF PART 70 PERMITS – GENERAL CONDITIONS

[COMAR 26.11.03.14] and [COMAR 26.11.03.06A(8)]

a. The Permittee shall submit an application to the Department to revise this Part 70 permit when required under COMAR 26.11.03.15 - .17.

b. When applying for a revision to a Part 70 permit, the Permittee shall comply with the requirements of COMAR 26.11.03.02 and .03 except that the application for a revision need include only information listed that is related to the proposed change to the source and revision to the permit. This information shall be sufficient to evaluate the proposed change and to determine whether it will comply with all applicable requirements of the Clean Air Act.

c. The Permittee may not change any provision of a compliance plan or schedule in a Part 70 permit as an administrative permit amendment or as a minor permit modification unless the change has been approved by the Department in writing.

d. A permit revision is not required for a change that is provided for in this permit relating to approved economic incentives, marketable permits, emissions trading, and other similar programs.

12. SIGNIFICANT PART 70 OPERATING PERMIT MODIFICATIONS

[COMAR 26.11.03.17]

The Permittee may apply to the Department to make a significant modification to its Part 70 Permit as provided in COMAR 26.11.03.17 and in accordance with the following conditions:

a. A significant modification is a revision to the federally enforceable provisions in the permit that does not qualify as an administrative permit amendment under COMAR 26.11.03.15 or a minor permit modification as defined under COMAR 26.11.03.16.

b. This permit does not preclude the Permittee from making changes, consistent with the provisions of COMAR 26.11.03, that would make the permit or particular terms and conditions of the permit irrelevant, such as by shutting down or reducing the level of operation of a source or of an emissions unit within the source. Air pollution control
equipment shall not be shut down or its level of operation reduced if doing so would violate any term of this permit.

c. Significant permit modifications are subject to all requirements of COMAR 26.11.03 as they apply to permit issuance and renewal, including the requirements for applications, public participation, and review by affected states and EPA, except:

(1) An application need include only information pertaining to the proposed change to the source and modification of this permit, including a description of the change and modification, and any new applicable requirements of the Clean Air Act that will apply if the change occurs;

(2) Public participation, and review by affected states and EPA, is limited to only the application and those federally enforceable terms and conditions of the Part 70 permit that are affected by the significant permit modification.

d. As provided in COMAR 26.11.03.15B(5), an administrative permit amendment may be used to make a change that would otherwise require a significant permit modification if procedures for enhanced preconstruction review of the change are followed that satisfy the requirements of 40 CFR 70.7(d)(1)(v).

e. Before making a change that qualifies as a significant permit modification, the Permittee shall obtain all permits-to-construct and approvals required by COMAR 26.11.02.

f. The Permittee shall not make a significant permit modification that results in a violation of any applicable requirement of the Clean Air Act.

g. The permit shield in COMAR 26.11.03.23 applies to a final significant permit modification that has been issued by the Department, to the extent applicable under COMAR 26.11.03.23.
13. **MINOR PERMIT MODIFICATIONS**

[COMAR 26.11.03.16]

The Permittee may apply to the Department to make a minor modification to the federally enforceable provisions of this Part 70 permit as provided in COMAR 26.11.03.16 and in accordance with the following conditions:

a. A minor permit modification is a Part 70 permit revision that:

   (1) Does not result in a violation of any applicable requirement of the Clean Air Act;

   (2) Does not significantly revise existing federally enforceable monitoring, including test methods, reporting, record keeping, or compliance certification requirements except by:

      (a) Adding new requirements,

      (b) Eliminating the requirements if they are rendered meaningless because the emissions to which the requirements apply will no longer occur, or

      (c) Changing from one approved test method for a pollutant and source category to another;

   (3) Does not require or modify a:

      (a) Case-by-case determination of a federally enforceable emissions standard,

      (b) Source specific determination for temporary sources of ambient impacts, or

      (c) Visibility or increment analysis;

   (4) Does not seek to establish or modify a federally enforceable permit term or condition for which there is no corresponding underlying applicable requirement of the Clean Air Act, but that the Permittee has assumed to avoid an applicable requirement to which the source would otherwise be subject, including:
(a) A federally enforceable emissions standard applied to the source pursuant to COMAR 26.11.02.03 to avoid classification as a Title I modification; and

(b) An alternative emissions standard applied to an emissions unit pursuant to regulations promulgated under Section 112(i)(5) of the Clean Air Act

(5) Is not a Title I modification; and

(6) Is not required under COMAR 26.11.03.17 to be processed as a significant modification to this Part 70 permit.

b. Application for a Minor Permit Modification

The Permittee shall submit to the Department an application for a minor permit modification that satisfies the requirements of COMAR 26.11.03.03 which includes the following:

(1) A description of the proposed change, the emissions resulting from the change, and any new applicable requirements that will apply if the change is made;

(2) The proposed minor permit modification;

(3) Certification by a responsible official, in accordance with COMAR 26.11.02.02F, that:

(a) The proposed change meets the criteria for a minor permit modification, and

(b) The Permittee has obtained or applied for all required permits-to-construct required by COMAR 26.11.03.16 with respect to the proposed change;

(4) Completed forms for the Department to use to notify the EPA and affected states, as required by COMAR 26.11.03.07-.12.

c. Permittee’s Ability to Make Change

(1) For changes proposed as minor permit modifications to this permit that will require the applicant to obtain a permit to construct, the permit to construct must be issued prior to the new change.
(2) During the period of time after the Permittee applies for a minor modification but before the Department acts in accordance with COMAR 26.11.03.16F(2):

(a) The Permittee shall comply with applicable requirements of the Clean Air Act related to the change and the permit terms and conditions described in the application for the minor modification.

(b) The Permittee is not required to comply with the terms and conditions in the permit it seeks to modify. If the Permittee fails to comply with the terms and conditions in the application during this time, the terms and conditions of both this permit and the application for modification may be enforced against it.

d. The Permittee is subject to enforcement action if it is determined at any time that a change made under COMAR 26.11.03.16 is not within the scope of this regulation.

e. Minor permit modification procedures may be used for Part 70 permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, but only to the extent that the minor permit modification procedures are explicitly provided for in regulations approved by the EPA as part of the Maryland SIP or in other applicable requirements of the Clean Air Act.

14. ADMINISTRATIVE PART 70 OPERATING PERMIT AMENDMENTS

[COMAR 26.11.03.15]

The Permittee may apply to the department to make an administrative permit amendment as provided in COMAR 26.11.03.15 and in accordance with the following conditions:

a. An application for an administrative permit amendment shall:

   (1) Be in writing;
(2) Include a statement certified by a responsible official that the proposed amendment meets the criteria in COMAR 26.11.03.15 for an administrative permit amendment, and

(3) Identify those provisions of this part 70 permit for which the amendment is requested, including the basis for the request.

b. An administrative permit amendment:

(1) Is a correction of a typographical error;

(2) Identifies a change in the name, address, or phone number of a person identified in this permit, or a similar administrative change involving the Permittee or other matters which are not directly related to the control of air pollution;

(3) requires more frequent monitoring or reporting by the Permittee;

(4) Allows for a change in ownership or operational control of a source for which the Department determines that no other revision to the permit is necessary and is documented as per COMAR 26.11.03.15B(4);

(5) Incorporates into this permit the requirements from preconstruction review permits or approvals issued by the Department in accordance with COMAR 26.11.03.15B(5), but only if it satisfies 40 CFR 70.7(d)(1)(v);

(6) Incorporates any other type of change, as approved by the EPA, which is similar to those in COMAR 26.11.03.15B(1)—(4);

(7) Notwithstanding COMAR 26.11.03.15B(1)—(6), all modifications to acid rain control provisions included in this Part 70 permit are governed by applicable requirements promulgated under Title IV of the Clean Air Act; or

(8) Incorporates any change to a term or condition specified as State-only enforceable, if the Permittee has obtained all necessary permits-to-construct and approvals that apply to the change.

c. The Permittee may make the change addressed in the application for an administrative amendment upon receipt by the Department of the application, if all permits-to-construct or approvals otherwise required
by COMAR 26.11.02 prior to making the change have first been obtained from the Department.

d. The permit shield in COMAR 26.11.03.23 applies to administrative permit amendments made under Section B(5) of COMAR 26.11.03.15, but only after the Department takes final action to revise the permit.

e. The Permittee is subject to enforcement action if it is determined at any time that a change made under COMAR 26.11.03.15 is not within the scope of this regulation.

15. OFF-PERMIT CHANGES TO THIS SOURCE

[COMAR 26.11.03.19]

The Permittee may make off-permit changes to this facility as provided in COMAR 26.11.03.19 and in accordance with the following conditions:

a. The Permittee may make a change to this permitted facility that is not addressed or prohibited by the federally enforceable conditions of this Part 70 permit without obtaining a Part 70 permit revision if:

(1) The Permittee has obtained all permits and approvals required by COMAR 26.11.02 and .03;

(2) The change is not subject to any requirements under Title IV of the Clean Air Act;

(3) The change is not a Title I modification; and

(4) The change does not violate an applicable requirement of the Clean Air Act or a federally enforceable term or condition of the permit.

b. For a change that qualifies under COMAR 26.11.03.19, the Permittee shall provide contemporaneous written notice to the Department and the EPA, except for a change to an emissions unit or activity that is exempt from the Part 70 permit application, as provided in COMAR 26.11.03.04. This written notice shall describe the change, including the date it was made, any change in emissions, including the pollutants emitted, and any new applicable requirements of the Clean Air Act that apply as a result of the change.
c. Upon satisfying the requirements of COMAR 26.11.03.19, the Permittee may make the proposed change.

d. The Permittee shall keep a record describing:

(1) Changes made at the facility that result in emissions of a regulated air pollutant subject to an applicable requirement of the Clean Air Act, but not otherwise regulated under this permit; and

(2) The emissions resulting from those changes.

e. Changes that qualify under COMAR 26.11.03.19 are not subject to the requirements for Part 70 revisions.

f. The Permittee shall include each off-permit change under COMAR 26.11.03.19 in the application for renewal of the part 70 permit.

g. The permit shield in COMAR 26.11.03.23 does not apply to off-permit changes made under COMAR 26.11.03.19.

h. The Permittee is subject to enforcement action if it is determined that an off-permit change made under COMAR 26.11.03.19 is not within the scope of this regulation.

16. ON-PERMIT CHANGES TO SOURCES

[COMAR 26.11.03.18]

The Permittee may make on-permit changes that are allowed under Section 502(b)(10) of the Clean Air Act as provided in COMAR 26.11.03.18 and in accordance with the following conditions:

a. The Permittee may make a change to this facility without obtaining a revision to this Part 70 permit if:

(1) The change is not a Title I modification;

(2) The change does not result in emissions in excess of those expressly allowed under the federally enforceable provisions of the Part 70 permit for the permitted facility or for an emissions
unit within the facility, whether expressed as a rate of emissions or in terms of total emissions;

(3) The Permittee has obtained all permits and approvals required by COMAR 26.11.02 and .03;

(4) The change does not violate an applicable requirement of the Clean Air Act;

(5) The change does not violate a federally enforceable permit term or condition related to monitoring, including test methods, record keeping, reporting, or compliance certification requirements;

(6) The change does not violate a federally enforceable permit term or condition limiting hours of operation, work practices, fuel usage, raw material usage, or production levels if the term or condition has been established to limit emissions allowable under this permit;

(7) If applicable, the change does not modify a federally enforceable provision of a compliance plan or schedule in this Part 70 permit unless the Department has approved the change in writing; and

(8) This permit does not expressly prohibit the change under COMAR 26.11.03.18.

b. The Permittee shall notify the Department and the EPA in writing of a proposed on-permit change under COMAR 26.11.03.18 not later than 7 days before the change is made. The written information shall include the following information:

(1) A description of the proposed change;

(2) The date on which the change is proposed to be made;

(3) Any change in emissions resulting from the change, including the pollutants emitted;

(4) Any new applicable requirement of the Clean Air Act; and

(5) Any permit term or condition that would no longer apply.
c. The responsible official of this facility shall certify in accordance with COMAR 26.11.02.02F that the proposed change meets the criteria for the use of on-permit changes under COMAR 26.11.03.18.

d. The Permittee shall attach a copy of each notice required by condition b. above to this Part 70 permit.

e. On-permit changes that qualify under COMAR 26.11.03.18 are not subject to the requirements for part 70 permit revisions.

f. Upon satisfying the requirements under COMAR 26.11.03.18, the Permittee may make the proposed change.

g. The permit shield in COMAR 26.11.03.23 does not apply to on-permit changes under COMAR 26.11.03.18.

h. The Permittee is subject to enforcement action if it is determined that an on-permit change made under COMAR 26.11.03.18 is not within the scope of the regulation or violates any requirement of the State air pollution control law.

17. FEE PAYMENT

[COMAR 26.11.02.16A(2) & (5)(b)]

a. The fee for this Part 70 permit is as prescribed in Regulation .19 of COMAR 26.11.02.

b. The fee is due on and shall be paid on or before each 12-month anniversary date of the permit.

c. Failure to pay the annual permit fee constitutes cause for revocation of the permit by the Department.
18. REQUIREMENTS FOR PERMITS-TO-CONSTRUCT AND APPROVALS

[COMAR 26.11.02.09.]

The Permittee may not construct or modify or cause to be constructed or modified any of the following sources without first obtaining, and having in current effect, the specified permits-to-construct and approvals:

a. New Source Review source, as defined in COMAR 26.11.01.01, approval required, except for generating stations constructed by electric companies;

b. Prevention of Significant Deterioration source, as defined in COMAR 26.11.01.01, approval required, except for generating stations constructed by electric companies;

c. New Source Performance Standard source, as defined in COMAR 26.11.01.01, permit to construct required, except for generating stations constructed by electric companies;

d. National Emission Standards for Hazardous Air Pollutants source, as defined in COMAR 26.11.01.01, permit to construct required, except for generating stations constructed by electric companies;

e. A stationary source of lead that discharges one ton per year or more of lead or lead compounds measured as elemental lead, permit to construct required, except for generating stations constructed by electric companies;

f. All stationary sources of air pollution, including installations and air pollution control equipment, except as listed in COMAR 26.11.02.10, permit to construct required;

g. In the event of a conflict between the applicability of (a.— e.) above and an exemption listed in COMAR 26.11.02.10, the provision that requires a permit applies.

h. Approval of a PSD or NSR source by the Department does not relieve the Permittee obtaining an approval from also obtaining all permits-to-construct required by (c.— g.) above.
19. CONSOLIDATION OF PROCEDURES FOR PUBLIC PARTICIPATION

[COMAR 26.11.02.11C] and [COMAR 26.11.03.01K]

The Permittee may request the Department to authorize special procedures for the Permittee to apply simultaneously, to the extent possible, for a permit to construct and a revision to this permit.

These procedures may provide for combined public notices, informational meetings, and public hearings for both permits but shall not adversely affect the rights of a person, including EPA and affected states, to obtain information about the application for a permit, to comment on an application, or to challenge a permit that is issued.

These procedures shall not alter any existing permit procedures or time frames.

20. PROPERTY RIGHTS

[COMAR 26.11.03.06E(4)]

This Part 70 permit does not convey any property rights of any sort, or any exclusive privileges.

21. SEVERABILITY

[COMAR 26.11.03.06A(5)]

If any portion of this Part 70 permit is challenged, or any term or condition deemed unenforceable, the remainder of the requirements of the permit continues to be valid.

22. INSPECTION AND ENTRY

[COMAR 26.11.03.06G(3)]

The Permittee shall allow employees and authorized representatives of the Department, the EPA, and local environmental health agencies, upon presentation of credentials or other documents as may be required by law, to:
a. Enter at a reasonable time without delay and without prior notification the Permittee’s property where a Part 70 source is located, emissions-related activity is conducted, or records required by this permit are kept;

b. Have access to and make copies of records required by the permit;

c. Inspect all emissions units within the facility subject to the permit and all related monitoring systems, air pollution control equipment, and practices or operations regulated or required by the permit; and

d. Sample or monitor any substances or parameters at or related to the emissions units at the facility for the purpose of determining compliance with the permit.

23. DUTY TO PROVIDE INFORMATION

[COMAR 26.11.03.06E(5)]

The Permittee shall furnish to the Department, within a reasonable time specified by the Department, information requested in writing by the Department in order to determine whether the Permittee is in compliance with the federally enforceable conditions of this Part 70 permit, or whether cause exists for revising or revoking the permit. Upon request, the Permittee shall also furnish to the Department records required to be kept under the permit.

For information claimed by the Permittee to be confidential and therefore potentially not discloseable to the public, the Department may require the Permittee to provide a copy of the records directly to the EPA along with a claim of confidentiality.

The Permittee shall also furnish to the Department, within a reasonable time specified by the Department, information or records requested in writing by the Department in order to determine if the Permittee is in compliance with the State-only enforceable conditions of this permit.
24. COMPLIANCE REQUIREMENTS

[COMAR 26.11.03.06E(1)] and [COMAR 26.11.03.06A(11)] and [COMAR 26.11.02.05]

The Permittee shall comply with the conditions of this Part 70 permit. Noncompliance with the permit constitutes a violation of the Clean Air Act, and/or the Environment Article Title 2 of the Annotated Code of Maryland and may subject the Permittee to:

a. Enforcement action,

b. Permit revocation or revision,

c. Denial of the renewal of a Part 70 permit, or

d. Any combination of these actions.

The conditions in this Part 70 permit are enforceable by EPA and citizens under the Clean Air Act except for the State-only enforceable conditions.

Under Environment Article Section 2-609, Annotated Code of Maryland, the Department may seek immediate injunctive relief against a person who violates this permit in such a manner as to cause a threat to human health or the environment.

25. CREDIBLE EVIDENCE

Nothing in this permit shall be interpreted to preclude the use of credible evidence to demonstrate noncompliance with any term of this permit.

26. NEED TO HALT OR REDUCE ACTIVITY NOT A DEFENSE

[COMAR 26.11.03.06E(2)]

The need to halt or reduce activity in order to comply with the conditions of this permit may not be used as a defense in an enforcement action.
27. CIRCUMVENTION

[COMAR 26.11.01.06]

The Permittee may not install or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total weight of emissions, conceals or dilutes emissions which would otherwise constitute a violation of any applicable air pollution control regulation.

28. PERMIT SHIELD

[COMAR 26.11.03.23]

A permit shield as described in COMAR 26.11.03.23 shall apply only to terms and conditions in this Part 70 permit that have been specifically identified as covered by the permit shield. Neither this permit nor COMAR 26.11.03.23 alters the following:

a. The emergency order provisions in Section 303 of the Clean Air Act, including the authority of EPA under that section;

b. The liability of the Permittee for a violation of an applicable requirement of the Clean Air Act before or when this permit is issued or for a violation that continues after issuance;

c. The requirements of the Acid Rain Program, consistent with Section 408(a) of the Clean Air Act;

d. The ability of the Department or EPA to obtain information from a source pursuant to Maryland law and Section 114 of the Clean Air Act; or

e. The authority of the Department to enforce an applicable requirement of the State air pollution control law that is not an applicable requirement of the Clean Air Act.

29. ALTERNATE OPERATING SCENARIOS

[COMAR 26.11.03.06A(9)]
For all alternate operating scenarios approved by the Department and contained within this permit, the Permittee, while changing from one approved scenario to another, shall contemporaneously record in a log maintained at the facility each scenario under which the emissions unit is operating and the date and time the scenario started and ended.
SECTION III   PLANT WIDE CONDITIONS

1. PARTICULATE MATTER FROM CONSTRUCTION AND DEMOLITION

[COMAR 26.11.06.03D]

The Permittee shall not cause or permit any building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne.

2. OPEN BURNING

[COMAR 26.11.07]

Except as provided in COMAR 26.11.07.04, the Permittee shall not cause or permit an open fire from June 1 through August 31 of any calendar year. Prior to any open burning, the Permittee shall request and receive approval from the Department.

3. AIR POLLUTION EPISODE

[COMAR 26.11.05.04]

When requested by the Department, the Permittee shall prepare in writing standby emissions reduction plans, consistent with good industrial practice and safe operating procedures, for reducing emissions creating air pollution during periods of Alert, Warning, and Emergency of an air pollution episode.

4. REPORT OF EXCESS EMISSIONS AND DEVIATIONS

[COMAR 26.11.01.07] and [COMAR 26.11.03.06C(7)]

The Permittee shall comply with the following conditions for occurrences of excess emissions and deviations from requirements of this permit, including those in Section VI – State-only Enforceable Conditions:

a. Report any deviation from permit requirements that could endanger human health or the environment, by orally notifying the Department immediately upon discovery of the deviation;
b. Promptly report all occurrences of excess emissions that are expected to last for one hour or longer by orally notifying the Department of the onset and termination of the occurrence;

c. When requested by the Department the Permittee shall report all deviations from permit conditions, including those attributed to malfunctions as defined in COMAR 26.11.01.07A, within 5 days of the request by submitting a written description of the deviation to the Department. The written report shall include the cause, dates and times of the onset and termination of the deviation, and an account of all actions planned or taken to reduce, eliminate, and prevent recurrence of the deviation;

d. The Permittee shall submit to the Department semi-annual monitoring reports that confirm that all required monitoring was performed, and that provide accounts of all deviations from permit requirements that occurred during the reporting periods. Reporting periods shall be January 1 through June 30 and July 1 through December 31, and reports shall be submitted within 30 days of the end of each reporting period. Each account of deviation shall include a description of the deviation, the dates and times of onset and termination, identification of the person who observed or discovered the deviation, causes and corrective actions taken, and actions taken to prevent recurrence. If no deviations from permit conditions occurred during a reporting period, the Permittee shall submit a written report that so states.

e. When requested by the Department, the Permittee shall submit a written report to the Department within 10 days of receiving the request concerning an occurrence of excess emissions. The report shall contain the information required in COMAR 26.11.01.07D(2).

5. ACCIDENTAL RELEASE PROVISIONS

[COMAR 26.11.03.03B(23)] and [40 CFR 68]

Should the Permittee become subject to 40 CFR 68 during the term of this permit, the Permittee shall submit risk management plans by the date specified in 40 CFR 68.150 and shall certify compliance with the requirements of 40 CFR 68 as part of the annual compliance certification as required by 40 CFR 70.
The Permittee shall initiate a permit revision or reopening according to the procedures of 40 CFR 70.7 to incorporate appropriate permit conditions into the Permittee’s Part 70 permit.

6. GENERAL TESTING REQUIREMENTS

[COMAR 26.11.01.04]

The Department may require the Permittee to conduct, or have conducted, testing to determine compliance with this Part 70 permit. The Department, at its option, may witness or conduct these tests. This testing shall be done at a reasonable time, and all information gathered during a testing operation shall be provided to the Department.

7. EMISSIONS TEST METHODS

[COMAR 26.11.01.04]

Compliance with the emissions standards and limitations in this Part 70 permit shall be determined by the test methods designated and described below or other test methods submitted to and approved by the Department.

Reference documents of the test methods approved by the Department include the following:

a. 40 CFR 60, appendix A

b. 40 CFR 51, appendix M

c. The Department’s Technical Memorandum 91-01 “Test Methods and Equipment Specifications for Stationary Sources”, (January 1991), as amended through Supplement 3, (October 1, 1997)

8. EMISSIONS CERTIFICATION REPORT

[COMAR 26.11.01.05-1] and [COMAR 26.11.02.19C] and [COMAR 26.11.02.19D]

The Permittee shall certify actual annual emissions of regulated pollutants from the facility on a calendar year basis.
a. The certification shall be on forms obtained from the Department and submitted to the Department not later than April 1 of the year following the year for which the certification is required;

b. The individual making the certification shall certify that the information is accurate to the individual’s best knowledge. The individual shall be:

(1) Familiar with each source for which the certifications forms are submitted, and

(2) Responsible for the accuracy of the emissions information;

c. The Permittee shall maintain records necessary to support the emissions certification including the following information if applicable:

(1) The total amount of actual emissions of each regulated pollutant and the total of all regulated pollutants;

(2) An explanation of the methods used to quantify the emissions and the operating schedules and production data that were used to determine emissions, including significant assumptions made;

(3) Amounts, types and analyses of all fuels used;

(4) Emissions data from continuous emissions monitors that are required by this permit, including monitor calibration and malfunction information;

(5) Identification, description, and use records of all air pollution control equipment and compliance monitoring equipment including:

(a) Significant maintenance performed,
(b) Malfunctions and downtime, and
(c) Episodes of reduced efficiency of all equipment;

(6) Limitations on source operation or any work practice standards that significantly affect emissions; and

(7) Other relevant information as required by the Department.
9. COMPLIANCE CERTIFICATION REPORT

[COMAR 26.11.03.06G(6) and (7)]

The Permittee shall submit to the Department and EPA Region III a report certifying compliance with each term of this Part 70 permit including each applicable standard, emissions limitation, and work practice for the previous calendar year by April 1 of each year.

a. The compliance certification shall include:

   (1) The identification of each term or condition of this permit which is the basis of the certification;

   (2) The compliance status;

   (3) Whether the compliance was continuous or intermittent;

   (4) The methods used for determining the compliance status of each source, currently and over the reporting period; and

   (5) Any other information required to be reported to the Department that is necessary to determine the compliance status of the Permittee with this permit.

b. The Permittee shall submit the compliance certification reports to the Department and EPA simultaneously.

10. CERTIFICATION BY RESPONSIBLE OFFICIAL

[COMAR 26.11.02.02F]

All application forms, reports, and compliance certifications submitted pursuant to this permit shall be certified by a responsible official as to truth, accuracy, and completeness. The Permittee shall expeditiously notify the Department of an appointment of a new responsible official.

The certification shall be in the following form:

“I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate
the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.”

11. SAMPLING AND EMISSIONS TESTING RECORD KEEPING

[COMAR 26.11.03.06C(5)]

The Permittee shall gather and retain the following information when sampling and testing for compliance demonstrations:

a. The location as specified in this permit, and the date and time that samples and measurements are taken;

b. All pertinent operating conditions existing at the time that samples and measurements are taken;

c. The date that each analysis of a sample or emissions test is performed and the name of the person taking the sample or performing the emissions test;

d. The identity of the Permittee, individual, or other entity that performed the analysis;

e. The analytical techniques and methods used; and

f. The results of each analysis.

12. GENERAL RECORDKEEPING

[COMAR 26.11.03.06C(6)]

The Permittee shall retain records of all monitoring data and information that support the compliance certification for a period of five (5) years from the date that the monitoring, sample measurement, application, report or emissions test was completed or submitted to the Department.

These records and support information shall include:
a. All calibration and maintenance records;

b. All original data collected from continuous monitoring instrumentation;

c. Records which support the annual emissions certification; and

d. Copies of all reports required by this permit.

13. GENERAL CONFORMITY

[COMAR 26.11.26.09]

The Permittee shall comply with the general conformity requirements of 40 CFR 93, Subpart B and COMAR 26.11.26.09.

14. ASBESTOS PROVISIONS

[40 CFR 61, Subpart M]

The Permittee shall comply with 40 CFR 61, Subpart M when conducting any renovation or demolition activities at the facility.

15. OZONE DEPLETING REGULATIONS

[40 CFR 82, Subpart F]

The Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for MVACs in subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the prohibitions and required practices pursuant to 40 CFR 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair or disposal of appliances shall comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.
c. Persons performing maintenance, service, repairs or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons performing maintenance, service, repairs or disposal of appliances shall certify with the Administrator pursuant to 40 CFR 82.162.

e. Persons disposing of small appliances, MVACS, and MVAC-like appliances as defined in 40 CFR 82.152, shall comply with record keeping requirements pursuant to 40 CFR 82.166.

f. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.

g. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

16. ACID RAIN PERMIT

The Permittee shall comply with the provisions and all applicable requirements of the renewal Phase II Acid Rain Permit, for the affected units that are being issued in conjunction with this permit. See Attached Appendix A.
SECTION IV  PLANT SPECIFIC CONDITIONS

This section provides tables that include the emissions standards, emissions limitations, and work practices applicable to each emissions unit located at this facility. The Permittee shall comply with all applicable emissions standards, emissions limitations and work practices included herein.

The tables also include testing, monitoring, record keeping and reporting requirements specific to each emissions unit. In addition to the requirements included here in Section IV, the Permittee is also subject to the general testing, monitoring, record keeping and reporting requirements included in Section III – Plant Wide Conditions of this permit.

Unless otherwise provided in the specific requirements for an emissions unit, the Permittee shall maintain at the facility for at least five (5) years, and shall make available to the Department upon request, all records that the Permittee is required under this section to establish. [Reference: COMAR 26.11.03.06C(5)(g)]

Table IV – 1

<table>
<thead>
<tr>
<th>Emissions Unit Number(s)</th>
<th>D-1, D-2 &amp; D-3: Boilers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBS and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, &amp; 3-0003)</td>
<td></td>
</tr>
</tbody>
</table>

1.0 Applicable Standards/Limits:

A. Control of Visible Emissions

COMAR 26.11.09.05A(2) – Fuel Burning Equipment

“Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity.”

COMAR 26.11.09.05A(3) - Exceptions. “Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and

The visible emissions do not occur for more than 6 consecutive minutes in
any sixty minute period.”
See Section VI-State Only for additional State only enforceable requirements.

B. Control of Particulate Matter Emissions

**COMAR 26.11.09.06B(3) – Solid Fuel Burning Equipment.** “A person may not cause or permit particulate matter caused by the combustion of solid fuel to be discharged into the atmosphere in excess of the amounts shown in Table 1.” *For these units, the maximum allowable emissions of particulate matter 0.03 gr/scfd @ 50% excess air.*

**COMAR 26.11.09.06C. Determination of Compliance (by stack test).**
“Compliance with the particulate matter emissions standards in this regulation shall be calculated as the average of 3 test runs using EPA Test Method 5 or other United States Environmental Protection Agency test method approved by the Department.”

**MATS Rule 40 CFR Part 63, Subpart UUUUU** – See Table IV-1e for additional filterable particulate matter standard.

C. Control of Sulfur Oxides

(1) **SIP Revision** - Sulfur emissions of solid fuel is limited to 2.8 lb. per million Btu averaged over a 24-hour period as determined by continuous in-stack measurement.
A review process to include emissions and ambient air quality levels in the vicinity of the plant shall be repeated by both parties in five year intervals beginning in the year 1985 and continuing thereafter. If at any time the Department determines that any applicable ambient air quality standard for sulfur oxides or any other compound if sulfur is likely to be exceeded, the Department shall notify the Permittee of such determination and the Permittee shall submit a timetable to purchase and use of complying fuel and achieve compliance within one (1) year after notification.
[Reference: §52.1070(d) EPA approved source- specific requirements. Potomac Electric Power Company (PEPCO) – Dickerson, #49352 Amended Consent Order, state effective 7/26/78]

(2) Emission Limitation for Power Plants requirements:
**COMAR 26.11.27.03C. SO\textsubscript{2} Emission Limitations.**
(1) Except as provided in §E of this regulation, annual SO\textsubscript{2} emissions from each affected electric generating unit may not exceed the number of tons in §C(2) of this regulation.
Table IV – 1

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>Annual SO₂ Tonnage Limitations Beginning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson Unit 1</td>
<td>1,238 tons</td>
</tr>
<tr>
<td>Dickerson Unit 2</td>
<td>1,355 tons</td>
</tr>
<tr>
<td>Dickerson Unit 3</td>
<td>1,285 tons</td>
</tr>
<tr>
<td>System-wide</td>
<td>18,541 tons</td>
</tr>
</tbody>
</table>

**COMAR 26.11.27.03E. System-Wide Compliance Determinations.**

1. Compliance with the emission limitations in §§B and C of this regulation may be achieved by demonstrating that the total number of tons emitted from all electric generating units in a system does not exceed the sum of the tonnage limitations for all electric generating units in that system.

2. A system-wide compliance determination shall be based only upon emissions from units in Maryland that are subject to the emission limitations in §§B and C of this regulation.

3. If a unit that is part of a system is transferred to a different person that does not own, operate, lease, or control an affected unit subject to this chapter, the transferred unit shall meet the limitations in §§B and C of this regulation applicable to that electric generating unit.

Please Note: Compliance with individual or System-wide SO₂ tonnage limitations is permitted.

3. Acid Rain Permit
The Permittee shall comply with the requirements of the Phase II Acid Rain Permit issued for this generating station. **Note:** A renewal Phase II Acid Rain Permit will be issued in conjunction with this Part 70 permit and is attached to the Part 70 permit as Appendix A.

4. Cross-State Air Pollution Rule
**TR SO₂ Group 1 - Trading Program 40 CFR Part 97 Subpart CCCC**
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635.

**Note:** §97.606(c) SO₂ emissions requirements. For TR SO₂ Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source’s compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all TR SO₂ Group 1 units at the source.
Table IV – 1

| Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO\textsubscript{2} Group 1 allowance transfer must be submitted for recordation in a TR SO\textsubscript{2} Group 1 source's compliance account in order to be available for use in complying with the source's TR SO\textsubscript{2} Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624. |

D. Control of Nitrogen Oxides
(1) NO\textsubscript{X} RACT Requirements

**COMAR 26.11.09.08B(5) - Operator Training.**

(a) For purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation.

(b) The operator training course sponsored by the Department shall include an in-house training course that is approved by the Department.”

**COMAR 26.11.09.08C - Requirements for Fuel-Burning Equipment with a Rated Heat Input Capacity of 250 Million Btu Per Hour or Greater.**

“(1) A person who owns or operates fuel-burning equipment with a rated heat input capacity of 250 Million Btu per hour or greater shall equip each installation with combustion modifications or other technologies to meet the NO\textsubscript{X} emission rates in §C(2) of this regulation.

(2) The maximum NO\textsubscript{X} emission rates as pounds of NO\textsubscript{X} per Million Btu per hour are:

(a) 0.45 for tangentially coal fired units located at an electric generating facility (excluding high heat release units);

(b) 0.50 for wall coal fired units located at an electric generating facility (excluding high heat release units);

(c) 0.30 for oil fired or gas/oil fired units located at an electric generating facility;

(d) 0.70 for coal fired cyclone fuel burning equipment located at an electric generating facility from May 1 through September 30 of each year and 1.5 during the period October 1 through April 30 of each year;

(e) 0.70 for a tangentially coal fired high heat release unit located at an electric generating facility;

(f) 0.80 for a wall coal fired high heat release unit located at an electric generating facility;

(g) 0.6 for coal fired cell burners at an electric generating facility; and

(h) 0.70 for fuel burning equipment stacks at a non-electric generating facility during the period May 1 through September 30 of each year and 0.99 during the period October 1 through April 30 of each year.

(3) A person who owns or operates fuel burning equipment with a rated heat
Table IV – 1

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>Annual NOₓ Tonnage Limitations Beginning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson Unit 1</td>
<td>554 tons January 1, 2012</td>
</tr>
<tr>
<td>Dickerson Unit 2</td>
<td>607 tons</td>
</tr>
<tr>
<td>Dickerson Unit 3</td>
<td>575 tons</td>
</tr>
<tr>
<td>System-wide</td>
<td>8,298 tons</td>
</tr>
</tbody>
</table>

(2) Emission Limitation for Power Plants requirements:

**COMAR 26.11.27.03B. NOₓ Emission Limitations.**

“(1) Except as provided in §E of this regulation, annual NOₓ emissions from each affected electric generating unit may not exceed the number of tons in §B(2) of this regulation.

(2) Annual Tonnage Limitations.

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>Ozone Season NOₓ Tonnage Limitations Beginning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson Unit 1</td>
<td>257 tons May 1, 2012</td>
</tr>
<tr>
<td>Dickerson Unit 2</td>
<td>274 tons</td>
</tr>
<tr>
<td>Dickerson Unit 3</td>
<td>259 tons</td>
</tr>
<tr>
<td>System-wide</td>
<td>3,567 tons</td>
</tr>
</tbody>
</table>

(3) Except as provided in §E of this regulation, ozone season NOₓ emissions from each affected electric generating unit may not exceed the number of tons in §B(4) of this regulation.”

“(6) Ozone Season Tonnage Limitations.

(7) Electric System Reliability During Ozone Seasons.

(a) An exceedance of the NOₓ limitations in §B(4) or (6) of this regulation which occurs because PJM Interconnection, LLC or a successor independent system operator, acts to invoke "Maximum Emergency Generation", "Load Reduction", "Voltage Reduction", "Curtailment of Non-essential Building Load", or "Manual Load Dump" procedures in accordance with the current PJM Manual, or a PJM alert preceding such action as to a generating unit that has temporarily shut down in order to avoid potential interruption in electric service and maintain electric system reliability is not a
violation of this chapter provided that:
(i) Within 36 hours following the action, the owner or operator of the affected electric generating unit or units notifies the Manager of the Air Quality Compliance Program of the action taken by PJM Interconnection and provides the Department with documentation of the action which is satisfactory to the Department;
(ii) Within 48 hours after completion of the action, the owner or operator of the affected unit or units provides the Department with the estimated NO$_X$ emissions in excess of the emission limitation; and
(iii) See State-only enforceable section of the permit for additional requirement.

(b) The owner or operator of an electric generating unit or system, as applicable, shall send written notice to the Manager of the Air Quality Compliance Program not later than 5 business days following the day when the cumulative ozone season NO$_X$ emissions of an electric generating unit or system, as applicable, are:
(i) Equal to approximately 80 percent of the applicable ozone season emission limitation; and
(ii) Equal to the applicable ozone season emission limitation. “

**COMAR 26.11.27.03E. System-Wide Compliance Determinations.**
“(1) Compliance with the emission limitations in §§B and C of this regulation may be achieved by demonstrating that the total number of tons emitted from all electric generating units in a system does not exceed the sum of the tonnage limitations for all electric generating units in that system.
(2) A system-wide compliance determination shall be based only upon emissions from units in Maryland that are subject to the emission limitations in §§B and C of this regulation.
(3) If a unit that is part of a system is transferred to a different person that does not own, operate, lease, or control an affected unit subject to this chapter, the transferred unit shall meet the limitations in §§B and C of this regulation applicable to that electric generating unit.”

**Please Note:** Compliance with individual or System-wide NO$_X$ tonnage limitations is permitted.

(3) Potomac River Consent Decree
The Permittee shall comply with the requirements of Potomac River Consent Decree. See **Table IV- 1a**

**Note:** The Consent Decree establishes a GenOn System-Wide Annual NO$_X$ Tonnage Limitation and a System-Wide Ozone Season NO$_X$ Emissions Limitation. Dickerson Units 1, 2 and 3 are included in the GenOn System. See the details of the Potomac River Consent Decree in the Fact Sheet for Emission Units D-1 thru D-3.
<table>
<thead>
<tr>
<th>Table IV – 1</th>
</tr>
</thead>
</table>

(4) Acid Rain Permit  
The Permittee shall comply with the requirements of the renewal Phase II Acid Rain Permit issued for this generating station. **Note:** A renewal Phase II Acid Rain Permit will be issued in conjunction with this Part 70 permit and is attached to the Part 70 permit as Appendix A.

(5) Cross-State Air Pollution Rule  
**TR NO\textsubscript{X} Annual Trading Program 40 CFR Part 97 Subpart AAAAA**

The Permittee shall comply with the provisions and requirements of §97.401 through §97.435.  
**Note:** §97.406(c) NO\textsubscript{X} emissions requirements. For TR NO\textsubscript{X} Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\textsubscript{X} Annual source and each TR NO\textsubscript{X} Annual unit at the source shall hold, in the source’s compliance account, TR NO\textsubscript{X} Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NO\textsubscript{X} emissions for such control period from all TR NO\textsubscript{X} Annual units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\textsubscript{X} Annual allowance transfer must be submitted for recordation in a TR NO\textsubscript{X} Annual source’s compliance account in order to be available for use in complying with the source’s TR NO\textsubscript{X} Annual emissions limitation for such control period in accordance with §§97.406 and 97.424.

**TR NO\textsubscript{X} Ozone Season Trading Program 40 CFR Part 97 Subpart BBBBB**

The Permittee shall comply with the provisions and requirements of §97.501 through §97.535.  
**Note:** §97.506(c) NO\textsubscript{X} emissions requirements. For TR NO\textsubscript{X} Ozone Season emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\textsubscript{X} Ozone Season source and each TR NO\textsubscript{X} Ozone Season unit at the source shall hold, in the source’s compliance account, TR NO\textsubscript{X} Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NO\textsubscript{X} emissions for such control period from all TR NO\textsubscript{X} Ozone Season units at the source.

Allowance transfer deadline means, for a control period in a given year,
midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\textsubscript{X} Ozone Season allowance transfer must be submitted for recordation in a TR NO\textsubscript{X} Ozone Season source’s compliance account in order to be available for use in complying with the source’s TR NO\textsubscript{X} Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524.

1.2 **Testing Requirements:**

A. **Control of Visible Emissions:**
For By-pass Stack: The Permittee shall perform quality assurance procedures on the continuous opacity monitoring system as established in COMAR 26.11.31. [Reference: COMAR 26.11.03.06C]

For Scrubber Stack: See Monitoring Requirements.

B. **Control of Particulate Matter:**
For By-pass Stack: See Monitoring Requirements.

For Scrubber Stack: The Permittee in accordance with COMAR 26.11.01.04A(1) and July 22, 1992 Consent Order, shall conduct annual testing. Annual testing shall be performed using EPA Reference Method 5 of 40 CFR Part 60 Appendix A (Section C). The Permittee shall submit a protocol to the Department for approval at least 30 days prior to the scheduled date of the test. [Reference: COMAR 26.11.03.06C]

The Permittee shall perform fuel sampling as follows: (1) Fuel sampling for solid fuel-fired units – one grab sample be taken as-bunkered or as-fired during each test run with the results of a proximate analysis for each sample included with the test report. Reported parameters shall include volatile matter, carbon, ash and sulfur contents and heating value in Btu/lb. [Reference: July 22, 1992 Consent Decree, Condition 1C- COMAR 26.11.03.06C].

C. **Control of Sulfur Oxides:**
1) See Monitoring Requirements.

2) Emission Limitation for Power Plants requirements
See Monitoring Requirements.

3) Acid Rain Permit
See Monitoring Requirements.
### Table IV – 1

| 4) Cross-State Air Pollution Rule |
| See Monitoring Requirements. |

D. Control of Nitrogen Oxides:
1) NO$_x$ RACT Requirements
See Monitoring Requirements.

2) Emission Limitation for Power Plants requirements:
See Monitoring Requirements.

3) Potomac River Consent Decree
See Monitoring Requirements.

4) Acid Rain Permit
See Monitoring Requirements.

5) Cross-State Air Pollution Rule
See Monitoring Requirements.

### 1.3 Monitoring Requirements:

A. Control of Visible Emissions
For By-pass Stack: The Permittee, in accordance with COMAR 26.11.01.10B, shall continuously monitor opacity of the stack gases using a continuous opacity monitor that is certified in accordance with 40 CFR Part 60, Appendix B and meets the quality assurance criteria of COMAR 26.11.31. [Reference: COMAR 26.11.01.10C]

No later than June 30, 2008, to conform with best practices in the industry, GenOn shall install a bag leak detection system on the baghouse serving Dickerson Units 1, 2 and 3 downstream of the baghouse. The bag leak detection system shall be equipped with an alarm system to alert facility personnel to elevated particulate levels in the flue gas stream from Dickerson Units 1, 2 and 3 and shall conform to the equipment specification requirements of 40 C.F.R. § 60.48Da(o)(4)(i)—(iv). [Reference: March 2008 Consent Decree paragraph 30]

For Scrubber Stack: See Monitoring for Particulate Matter from Scrubber Stack.

B. Control of Particulate Matter:
For By-pass Stack: See the requirements of CAM Plan.
Table IV – 1

For the Scrubber Stack: The Permittee shall operate and maintain a particulate emissions monitoring system (PEMS). [Reference: COMAR 26.11.03.06C]. Note: The MATS Rule also requires PEMS

C. Control of Sulfur Oxides
For 1) through 3):
The Permittee shall continuously monitor sulfur dioxide emissions using a CEM that meet the requirements of 40 CFR Part 75, Subpart B §75.10A(1) & (2). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with SO₂ standard, the Health Air Act limitations, and the Acid Rain Program. [Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, July 22, 1992 Consent Decree and Acid Rain Permit].
The Permittee shall perform quality control/quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. [Reference: COMAR 26.11.01.11C]

4) Cross-State Air Pollution Rule
The Permittee shall comply with the monitoring requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633.

D. Control of Nitrogen Oxides
For 1) through 4):
The Permittee shall continuously monitor NOₓ emissions that meet the requirements of 40 CFR Part 75, Subpart B §75.10A(2). This continuous monitoring system shall be used to collect emissions information to demonstrate the SIP NOₓ standard, the Healthy Air Act limitations, the Potomac River Consent Decree, and the Acid Rain Program. [Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, Potomac Consent Decree, July 22, 1992 Consent Decree and Acid Rain Permit].
The Permittee shall perform quality control/quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. [Reference: COMAR 26.11.01.11C]
The Permittee shall certify CEMs in accordance with 40 CFR Part 75, Appendix A. [Reference: COMAR 26.11.09.08B(2)(b)]

5) Cross-State Air Pollution Rule
The Permittee shall comply with the monitoring requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the NOₓ Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NOₓ Ozone Season Trading Program.
1.4 **Record Keeping Requirements:**

**Note:** All records must be maintained for a period of at least 5 years. [Reference: COMAR 26.11.03.06C(5)(g)]

<table>
<thead>
<tr>
<th>A. Control of Visible Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Permittee shall maintain all records necessary to comply with the data reporting requirements by COMAR 26.11.01.11E on file. [Reference COMAR 26.11.01.11E]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>B. Control of Particulate Matter:</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Permittee shall maintain records of all particulate matter emissions tests and PEMS hourly data. [Reference: COMAR 26.11.03.06C]</td>
</tr>
</tbody>
</table>

The Permittee shall maintain records as required by CAM Plan See Table IV-1b.

<table>
<thead>
<tr>
<th>C. Control of Sulfur Oxides</th>
</tr>
</thead>
<tbody>
<tr>
<td>1) The Permittee shall maintain all records necessary to comply with data reporting requirements of COMAR 26.11.01.11E. [Reference COMAR 26.11.01.11E].</td>
</tr>
</tbody>
</table>

2) Emission Limitation for Power Plants Requirements:
The Permittee shall maintain records sufficient to demonstrate compliance with the requirements of the Healthy Air Act, COMAR 26.11.27. [Reference: COMAR 26.11.01.05A].

3) Acid Rain Permit
The Acid Rain Permit contains program specific recordkeeping requirements. [Reference: 40 CFR Part 75, Subpart F].

4) Cross-State Air Pollution Rule
The Permittee shall comply with the recordkeeping requirements found in §97.606, §97.630, and §97.634.

<table>
<thead>
<tr>
<th>D. Control of Nitrogen Oxides</th>
</tr>
</thead>
<tbody>
<tr>
<td>1) NO\textsubscript{x} RACT Requirements</td>
</tr>
<tr>
<td>The Permittee shall maintain records necessary for the quarterly emission reports. [Reference: COMAR 26.11.03.06C]</td>
</tr>
</tbody>
</table>

2) Emission Limitation for Power Plants requirements:
The Permittee shall maintain records sufficient to demonstrate compliance with the requirements of the Healthy Air Act, COMAR 26.11.27. [Reference: COMAR 26.11.01.05A].

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**Table IV – 1**
### Table IV – 1

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<thead>
<tr>
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<tbody>
<tr>
<td>3) Potomac River Consent Decree</td>
<td>The Permittee shall comply with the recordkeeping requirements of the Potomac River Consent Decree. See paragraph 17 in Table IV-1a: Potomac River Consent Decree. [Reference: COMAR 26.11.03.06C]</td>
</tr>
<tr>
<td>4) Acid Rain Permit</td>
<td>The Acid Rain Permit contains program specific recordkeeping requirements. [Reference: 40 CFR Part 75, Subpart F].</td>
</tr>
<tr>
<td>5) Cross-State Air Pollution Rule</td>
<td>The Permittee shall comply with the recordkeeping requirements found in §97.406, §97.430, and §97.434 for the NOₓ Annual Trading Program and §97.506, §97.530, and §97.534 for the NOₓ Ozone Season Trading Program.</td>
</tr>
</tbody>
</table>

### 1.5 Reporting Requirements:

**A. Control of Visible Emissions**

The Permittee shall report:

All CEM system downtime that lasts or is expected to last more than 24 hours shall be reported to the Department by telephone before 10 a.m. of the first regular business day following the breakdown.

The system breakdown report required by Sec. G(1)(a) of this regulation shall include the reason, if known, for the breakdown and the estimated period of time that the CEM will be down. The owner or operator of the CEM shall notify the Department by telephone when an out-of-service CEM is back in operation and producing valid data. [Reference: COMAR 26.11.01.11E]

The Permittee shall submit:

Quarterly summary reports to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:

(i) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards;

(ii) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;

(iii) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;

(iv) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;

(v) Quarterly quality assurance activities; and
Table IV – 1

(vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and
(vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation.” [Reference: COMAR 26.11.01.11E]

B. Control of Particulate Matter:
The Permittee shall submit a test protocol/notifications to the Department at least 30 days prior to test and notify the Department at least 10 days prior to testing. The Permittee shall report the results of the particulate emissions stack test to the Department within 45 days after completion of the testing. [Reference: COMAR 26.11.03.06C]

The Permittee shall submit a quarterly report of the PEMS data. [Reference: COMAR 26.11.03.06C]

The Permittee shall submit reports records as required by CAM Plan. See Table IV-1b.

C. Control of Sulfur Oxides
1) The Permittee shall submit annual fuel usage reports to the Department for all fuel-burning equipment and combustion turbines owned and/or operated by the Permittee in the State of Maryland. The annual report shall contain the type and quantity of each fuel used, the average sulfur content, average heating value of each fuel, and the number of hours and the approximate number of days the equipment operated. The annual report shall also contain the annual capacity factor for each of the electric generating unit. The annual fuel usage report shall be submitted no later than 60 calendar days following each calendar year. [Reference: July 22, 1992 Consent Decree, Condition 6]

The Permittee shall submit a quarterly summary report to the Department not later than 30 days following each calendar quarter that contains the information listed in COMAR 26.11.01.11E. [Reference: COMAR 26.11.01.11E(2)].

2) Emission Limitation for Power Plants Requirements:
COMAR 26.11.27.05 - Monitoring and Reporting Requirements.
B. Beginning with calendar year 2007 and each year thereafter, the owner or operator of each electric generating unit subject to this chapter shall submit an annual report to the Department, the Department of Natural Resources, and the Public Service Commission. The report for each calendar year shall be
submitted not later than March 1 of the following year.

C. Each report shall include:
(1) Emissions performance results related to compliance with the emission requirements under this chapter;
(2) Emissions of NOX and SO2, and beginning with calendar year 2010, mercury, emitted during the previous calendar year from each affected unit;
(3) A current compliance plan; and
(4) Any other information requested by the Department.

3) Acid Rain Permit
The Acid Rain Permit contains program specific reporting requirements. [Reference: 40 CFR Part 75, Subpart G].

4) Cross-State Air Pollution Rule
The Permittee shall comply with the reporting requirements found in §97.606, §97.630, §97.633 and §97.634.

D. Control of Nitrogen Oxides
1) NOX RACT Requirements
The Permittee shall submit quarterly emission reports of CEM data to the Department on or before the thirtieth day of the month following the end of each calendar quarter. The emissions report shall contain the information required by COMAR 26.11.01.11E. [Reference: COMAR 26.11.09.08K(1) and COMAR 26.11.03.06C]

2) Emission Limitation for Power Plants Requirements:
COMAR 26.11.27.05 - Monitoring and Reporting Requirements.
B. Beginning with calendar year 2007 and each year thereafter, the owner or operator of each electric generating unit subject to this chapter shall submit an annual report to the Department, the Department of Natural Resources, and the Public Service Commission. The report for each calendar year shall be submitted not later than March 1 of the following year.
C. Each report shall include:
(1) Emissions performance results related to compliance with the emission requirements under this chapter;
(2) Emissions of NOX and SO2, and beginning with calendar year 2010, mercury, emitted during the previous calendar year from each affected unit;
(3) A current compliance plan; and
(4) Any other information requested by the Department.

3) Potomac River Consent Decree
The Permittee shall comply with the reporting requirements of the Potomac River Consent Decree. See paragraphs 15 and 18 through 23 in Table IV-1a:
### Table IV – 1

<table>
<thead>
<tr>
<th>Potomac River Consent Decree. [Reference: COMAR 26.11.03.06C]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4) Acid Rain Permit</td>
</tr>
<tr>
<td>The Acid Rain Permit contains program specific reporting requirements. [Reference: 40 CFR Part 75, Subpart G].</td>
</tr>
<tr>
<td>5) Cross-State Air Pollution Rule</td>
</tr>
<tr>
<td>The Permittee shall comply with the reporting requirements found in §97.406, §97.430, §97.433 and §97.434 for the NOX Annual Trading Program and §97.506, §97.530, §97.533, and §97.534 for the NOX Ozone Season Trading Program.</td>
</tr>
</tbody>
</table>

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”

### Table IV – 1a – Potomac River Consent Decree

| 1a.0 | Emissions Unit Number(s): D-1, D-2 & D-3: Boilers Cont’d |
|----------------------------------------------------------|
| **Potomac River Consent Decree** |
| Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003) |

| 1a.1 | Applicable Standards/Limits: |
|------------------------------------------------|
| Control of Nitrogen Oxides |
| System-wide Annual Tonnage Limitations for NO\textsubscript{X} |
| 1. Except as provided in Paragraph 185,188, or 189 as applicable, GenOn shall comply with the following System-Wide Annual Tonnage Limitations for NO\textsubscript{X}, which apply to all Units collectively within the GenOn System, during each year specified in Table A below: |
| [Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 57.] |

**Note:** The GenOn system consists of Chalk Point Generating Station Unit 1 and Unit 2; Dickerson Generating Station Unit 1, Unit 2, and Unit 3; Morgantown Generating Station Unit 1 and Unit 2; and Potomac River Generating Station Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5. *(Potomac Generating Station Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5)*
2. Except as provided in Paragraph 185, 188, or 189 as applicable, beginning May 1, 2004, for each Ozone Season specified, the sum of the tons by all Units within the GenOn System, shall not exceed the following System-Wide Ozone Season Tonnage Limitations for NO\textsubscript{X} in Table B below:

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 58.]

**Table A**

<table>
<thead>
<tr>
<th>Applicable Year</th>
<th>System-Wide Annual Tonnage Limitations for NO\textsubscript{X}</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 and each year after</td>
<td>16,000 tons</td>
</tr>
</tbody>
</table>

3. Except as provided in Paragraph 185, 188, or 189 as applicable, beginning May 1, 2008, and continuing for each and every Ozone Season thereafter, the GenOn System, shall not exceed a System-Wide Ozone Season Emissions Rate of 0.150 lb/mm Btu NO\textsubscript{X}.

**Table B**

<table>
<thead>
<tr>
<th>Applicable Ozone Season</th>
<th>System-Wide Ozone Season Tonnage Limitations for NO\textsubscript{X}</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 and each ozone season</td>
<td>5,200 tons</td>
</tr>
</tbody>
</table>

4. If GenOn exceeds the limitations specified in Section IV, Subsection C (System-Wide Annual Tonnage Limitations for NO\textsubscript{X}) or D (System-Wide Ozone Season Emissions Limitations), GenOn may not claim compliance with this Decree by using, tendering, or otherwise applying NO\textsubscript{X} Allowances that were obtained prior to lodging of this Decree, or that are
subsequently purchased or otherwise obtained, and stipulated penalties apply as set forth in Section XI (Stipulated Penalties). Except as provided in Paragraphs 61 and 66, NO\textsubscript{X} Allowances allocated to, or purchased by, or on behalf of, the GenOn System may not be used by GenOn to meet its own federal and/or State Clean Air Act regulatory requirements to the extent otherwise allowed by law. 

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 60.]

5. Solely for the purpose of compliance with any present or future NO\textsubscript{X} trading program set forth in the Maryland State Implementation Plan including, the Maryland NO\textsubscript{X} Reduction and Trading Program, COMAR 26.11.29-26.11.30, beginning with:

- (a) the 2004 Ozone Season and during each Ozone Season thereafter, and
- (b) the year that an annual NO\textsubscript{X} allowance trading program becomes effective in Maryland, and during each year thereafter,

GenOn must first use: (1) any and all allowances previously held by GenOn; and (2) allowances allocated to individual plants within the GenOn System. Only to the extent that such allowances are insufficient to establish compliance with the requirements of those SIPs, GenOn may use NO\textsubscript{X} Allowances purchased or otherwise obtained from sources outside the GenOn System. 

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 61.]

6. Except as provided in this Consent Decree, GenOn shall not sell or trade any NO\textsubscript{X} Allowances allocated to the GenOn System that would otherwise be available for sale or trade as a result of GenOn’s compliance with any of the NO\textsubscript{X} emission limitations specified in this Consent Decree. 

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 62.]

7. Provided that GenOn is in compliance with all of the NO\textsubscript{X} emission limitations specified in the Consent Decree, including both unit-specific and system-wide emissions rates and plant-wide and system-wide tonnage limitations, nothing in this Consent Decree shall preclude GenOn from selling or transferring NO\textsubscript{X} Allowances allocated to the GenOn System that become available for sale or trade when, and only insofar as, both: (a) the total Ozone Season NO\textsubscript{X} emissions from all Units within the GenOn System are below System Wide Ozone Season Tonnage Limitations for the applicable year, as specified in Paragraph 58; and (b) the annual NO\textsubscript{X} emissions from all Units within the GenOn System are below the System-
Table IV – 1a – Potomac River Consent Decree

8. In no event shall the emission reductions required by this Decree be considered as credible contemporaneous emission decreases for the purpose of obtaining a netting credit under the Clean Air Act’s Nonattainment NSR and PSD programs.

9. In order to sell or transfer NO\textsubscript{X} Allowances pursuant to Paragraph 63, GenOn must also timely report the generation of such NO\textsubscript{X} Allowances in accordance with Section IX (Periodic Reporting) of this Consent Decree.

10. For purpose of this Subsection, the “surrender of allowances” means permanently surrendering NO\textsubscript{X} Allowances from the accounts administered by Plaintiffs for all Units in the GenOn System, so that such allowances can never be used to meet any compliance requirement of any person under the Clean Air Act, the Maryland and Virginia SIPs, or this Consent Decree.
12. If any NO\textsubscript{X} Allowances are transferred directly to a non-profit third party, GenOn shall include a description of such transfer in the next report submitted to Plaintiffs. Such report shall: (a) provide the identity of the non-profit third party recipient(s) of the NO\textsubscript{X} Allowances and a listing of the serial numbers of the transferred NO\textsubscript{X} Allowances; and (b) include a certification by the third-party recipient(s), stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NO\textsubscript{X} Allowances and will not use any of the Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NO\textsubscript{X} Allowances, GenOn shall include a statement that the third-party recipient(s) tendered the NO\textsubscript{X} Allowances for permanent surrender to Plaintiffs in accordance with the provisions of Paragraph 68 within one (1) year after GenOn transferred the NO\textsubscript{X} Allowances to them. GenOn shall not have complied with the NO\textsubscript{X} Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred NO\textsubscript{X} Allowances to Plaintiffs.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 67]

13. For all NO\textsubscript{X} Allowances surrendered to Plaintiffs, GenOn or the non-profit third-party recipient(s) (as the case may be) shall first submit a NO\textsubscript{X} Allowance transfer request form to EPA directing the transfer of such NO\textsubscript{X} Allowances to the Plaintiffs’ Enforcement Surrender Account or to any other Plaintiffs account that Plaintiffs may direct in writing. As part of submitting these transfer requests, GenOn or the third-party recipient(s) shall irrevocably authorize the transfer of these NO\textsubscript{X} Allowances and identify- by name of account and any applicable serial or other identification numbers or station names- the source and location of the NO\textsubscript{X} Allowances being surrendered.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 68]

Severance of the Morgantown and/or Dickerson Plants from the GenOn System

14. GenOn shall comply with paragraphs 185,186,187,188,189,190, 191,192,193,194,195 of Section XIX. Severing the Morgantown Plant: Revised System-wide NO\textsubscript{X} Emission Limitations, Section XX. Severing the Dickerson Plant: Revised System-wide NO\textsubscript{X} Emission Limitations, XXI Severing the Morgantown and Dickerson Plants: Revised System-wide NO\textsubscript{X} Emission Limitations, and Section XXII. Sales or Transfers of Ownership Interests.

[Reference: GenOn Potomac River Consent Decree, Sections XIX, XX,
<table>
<thead>
<tr>
<th>XXI, and XXII]</th>
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</thead>
<tbody>
<tr>
<td>15. GenOn shall comply with the reporting requirements of paragraph 138 and 139 of Section XVII Severance of the Morgantown and/or Dickerson Plants from the GenOn System.</td>
</tr>
<tr>
<td>[Reference: GenOn Potomac River Consent Decree, Section XVII, paragraphs 138 and 139]</td>
</tr>
</tbody>
</table>

**Monitoring, and Record Keeping and Reporting Requirements**

16. In determining Emission Rates for NO\textsubscript{X}, GenOn shall use CEMs in accordance with those reference methods specified in 40 CFR Part 75.  
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 69]

17. GenOn shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors’ or agents’ possession or control, and that directly relate to GenOn’s performance of its obligations under this Consent Decree until December 31, 2015. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.  
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 131]

18. GenOn shall submit a report to Plaintiffs containing a summary of the data recorded by each NO\textsubscript{X} CEMs in the GenOn System, expressed in lb/mmBtu, on a 30-day rolling average basis, in electronic format, within 30 days after the end of each calendar quarter and within 30 days after the end of each month of the Ozone Season, and shall make all data recorded available to the Plaintiffs upon request.  
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 70]

*Completed (19, 20 & 21): [Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 88, 89 & 90]*

22. In addition to the progress reports required pursuant to this Section, GenOn shall provide a written report to Plaintiffs of any violation of the requirements of this Consent Decree, including exceedances of any Unit-specific 30-Day Rolling Average Emission Rates, Unit-specific 30-Day Rolling Average Removal Efficiencies, any Unit-specific 12-Month Rolling Average Removal Efficiencies, System-Wide Annual Tonnage Limitations, System-Wide Ozone Season Tonnage Limitations, Potomac River Annual
or Ozone Season Tonnage Limitations, or System-Wide Ozone Season Emission Rate, within ten (10) business days of when GenOn knew or should have known of any such violation. In this report, GenOn shall explain the cause or causes of the violation and all measures taken or to be taken by GenOn to prevent such violations in the future.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 91]

23. Each GenOn report shall be signed by GenOn’s Director, Environmental Safety and Health, GenOn Mid-Atlantic, LLC, or in his or her absence, the President of GenOn Mid-Atlantic, LLC, or higher ranking official, and shall contain the following certification:

This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 92]

24. If any Allowances are surrendered to any non-profit third party, in accordance with this Consent Decree, the third party’s certification shall be signed by a managing officer of the third party and shall contain the following language:

I certify under penalty of law that [name of third party] will not sell, trade, or otherwise exchange any of the [NOx, SO2, or Mercury] Allowances and will not use any of the Allowances to meet any obligation imposed by an environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 93]

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”
### Table IV-1b

**Compliance Assurance Monitoring (CAM) Plan**

**Baghouse and Electrostatic Precipitator (ESP) for UNITS D-1, D-2 & D-3 (Bypass Stack only)**

<table>
<thead>
<tr>
<th>Applicable Requirement</th>
<th>PM: Emission limit: 0.03 gr/scfd@ 50% EA (COMAR 26.11.09.06B(3)) Opacity: 10 percent maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Indicator</td>
<td>Indicator #1</td>
</tr>
<tr>
<td></td>
<td>Opacity at Stack</td>
</tr>
<tr>
<td>Measurement Approach</td>
<td>The common stack continuous opacity monitor (COM) produces 1-minute average readings, which are then used to produce 6-minute averages and 1-hour averages</td>
</tr>
<tr>
<td>II. Indicator Range</td>
<td>The opacity indicator range is block hourly average opacity of 9.8%. When the block hourly average opacity is over 9.8%, operators must review ESP and Baghouse performance checklist and document.</td>
</tr>
<tr>
<td>III. Performance Criteria</td>
<td></td>
</tr>
<tr>
<td>1. Data Representativeness</td>
<td>The COM was installed on the stack per 40 CFR 60, Appendix B.</td>
</tr>
<tr>
<td>2. AQ/QC Practices and Criteria</td>
<td>QA/QC per 40 CFR 60, Appendix B</td>
</tr>
<tr>
<td>3. Monitoring Frequency</td>
<td>Opacity is monitored continuously by the continuous opacity monitoring (COM) system.</td>
</tr>
<tr>
<td>4. Record keeping</td>
<td>Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.</td>
</tr>
<tr>
<td>5. (i) Reporting</td>
<td>Report the number, duration and cause of any excursion and the corrective action taken.</td>
</tr>
<tr>
<td></td>
<td>(ii) Frequency Quarterly</td>
</tr>
</tbody>
</table>

---

### Table IV – 1c – CPCN 9087: FGD System

**1c.0 Emissions Unit Number(s): FGD System for D-1 D-2 and D-3**

A wet flue gas desulfurization (FGD) system is installed on D-1, D-2 and D-3. The FGD system controls acid gases (SO₂ & HCl) and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing a gypsum by-product. The FGD system consists of the following subsystems: 1. Limestone unloading and storage facilities; 2. Limestone slurry preparation and feed; 3. SO₂ absorption tower; 4. Gypsum dewatering and loading facilities; and 5. Two emergency diesel engines.  
[CPCN: 9087]

**1c.1 Applicable Standards/Limits:**
[Reference: CPCN 9087: II. Applicable Air Quality Regulations]

10. The Dickerson facility is subject to all applicable, federally enforceable State air quality requirements including, but not limited to, the following regulations:
<table>
<thead>
<tr>
<th>Table IV – 1c – CPCN 9087: FGD System</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) COMAR 26.11.01.10– Requires GenOn to install Continuous Opacity Monitoring (COM) systems to monitor opacity and Continuous Emissions Monitoring (CEM) systems (COMAR 26.11.01.11) to monitor SO₂, NOₓ and either O₂ or CO₂ from each boiler, and to meet applicable CEM installation, certification, operating, monitoring, testing, and, malfunction requirements in 40 CFR Part 60, 40 CFR Part 75, and 40 CFR Part 51, Appendix P, §3.3-3.8 or §3.9 as incorporated by reference.</td>
</tr>
<tr>
<td>b) COMAR 26.11.03.19– Requires GenOn to update the existing Part 70 Operating Permit [No. 24-031-00019] to include applicable APC Project requirements.</td>
</tr>
<tr>
<td>c) COMAR 26.11.06.02C(2)– Prohibits GenOn from causing or permitting the discharge of emissions from any installation or building (i.e., confined, non-fuel-burning equipment sources) other than water in an uncombined form, which are visible to human observers. The visible emissions standard do not apply to emissions during startup and process modifications or adjustments, or occasional cleaning of control equipment, if (a) the visible emissions are not greater than 40% opacity; and (b) the visible emissions do not occur for more than 6 consecutive minutes in any 60-minute period.</td>
</tr>
<tr>
<td>d) COMAR 26.11.06.03B(2)(a)– Prohibits GenOn from discharging into the outdoor atmosphere from any non-fuel burning confined source (i.e., the limestone, gypsum and other material storage silos, enclosed material transfer points, etc) particulate matter in excess of 0.03 grains per dry standard cubic feet (gr/scfd)(68.7 mg/dscm).</td>
</tr>
<tr>
<td>e) COMAR 26.11.06.03C(1)– Prohibits GenOn from causing or permitting emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne,</td>
</tr>
<tr>
<td>f) COMAR 26.11.06.03D– Prohibits GenOn from causing or permitting any material to be handled, transported, or stored, or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. For the unloading, loading and transfer of the materials included at the Dickerson APC Project (limestone, gypsum, sorbent to control sulfuric acid mist emissions, and hydrated lime in wastewater treatment plant operations), these reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer:</td>
</tr>
<tr>
<td>i) Use of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land.</td>
</tr>
<tr>
<td>ii) Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can create airborne dusts.</td>
</tr>
</tbody>
</table>
Table IV – 1c – CPCN 9087: FGD System

iii) Installation and use of hoods, fans, and dust collectors to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting of buildings or other similar operations.

iv) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution. Alternate means may be employed to achieve the same results as would covering the vehicles.

v) The paving of roadways and their maintenance in clean condition.

vi) The prompt removal from paved streets of earth or other material which has been transported there by trucks or earth moving equipment or erosion by water.

g) COMAR 26.11.06.12-Prohibits GenOn from constructing, modifying or operating or causing to be constructed, modified, or operated, a New Source Performance Standard (NSPS) source as defined in COMAR 26.11.01.01C, which results in violation of provisions of 40 CFR Part 60.

h) COMAR 26.11.09.03-When determining compliance with applicable particulate matter emission standards from boiler stacks (concentration requirement expressed as grains per standard cubic foot or milligrams per cubic meter of dry exhaust gas), GenOn shall correct to 50 percent excess air. In addition, when determining compliance with a mass-based particulate matter emission limit expressed as pounds per million Btu (lb/MBtu), GenOn shall use the procedures for determining particulate matter emission rates in 40 CFR Part 60 Appendix A, Method 19.

i) COMAR 26.11.09.05E(2) through E(4)-Prohibits the discharge of emissions from quench pump engine when operating at idle, greater than 10 percent opacity, and when in operating mode, greater than 40 percent opacity. Exceptions: (i) limitations when operating at idle do not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system; (ii) limitations when operating at idle do not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods: engines that are idled continuously when not in service: 30 minutes and all other engines: 15 minutes; (iii) limitations when in idle and operating modes do not apply while maintenance, repair, or testing is being performed by qualified mechanics.

j) COMAR 26.11.009.06B(3)-Prohibits GenOn from discharging particulate matter into the atmosphere caused by the combustion of solid fuel in Units 1, 2, and 3 in excess of 0.03 gr/dscf, corrected to 50% excess air.

k) COMAR 26.11.09.07A(2)(b)-Prohibits GenOn from burning distillate fuel oil in the quench pumps with a sulfur content greater than 0.3 percent.

l) COMAR 26.11.27-Requires GenOn to comply with the applicable emissions limitations for NOx, SO2 and mercury, and the monitoring and record keeping requirements contained in COMAR 26.11.27.
Table IV – 1c – CPCN 9087: FGD System


12. The equipment at Dickerson identified in [CPCN 9087] Tables 1a, 1b and 2 are subject to NSPS 40 CFR Part 60, Subpart OOO-Standards of Performance for Non-metallic Mineral Processing Plants (40 CFR §60.670) and the associated notification and testing requirements of 40 CFR §60.7, §60.8 and §60.11 whose requirements include, but are not limited to the following:

   a) GenOn shall not cause to be discharged into the atmosphere gases from any transfer point along the belt conveyor systems, or any other stack, particulate matter in concentrations greater than 0.022 gr/dscf or opacity that is greater than seven percent.

   b) GenOn shall not cause to be discharged into the atmosphere from any transfer point along the belt conveyor system or from any other affected facility any fugitive emissions which exhibit greater than 10 percent opacity. If the transfer point is totally enclosed in a building or enclosure, then there are no fugitive emissions allowed from the building unless they are directed through a vent, which is limited by Condition 12(a).

   c) GenOn shall not cause to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions which exhibit greater than 15 percent opacity.

   d) GenOn shall not cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity.

13. The 252-horsepower diesel engine-driven quench pump and the 227-horsepower diesel fire pump at the Dickerson facility are subject to New Source Performance Standards (NSPS) 40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR §60.4205) and the associated fuel, monitoring, compliance, testing, notification, reporting and record keeping requirements (40 CFR §60.4200 et seq.), and related applicable provisions of 40 CFR §60.7 and §60.8.

[Reference: CPCN 9087: IV. Operational Restrictions and Limitations]

14. GenOn shall:
   a) Install, maintain and operate the new limestone, gypsum, unloading, storage, transfer and distribution equipment and systems with associated particulate matter control methods listed in [CPCN 9087] Tables 1a-b and Table 2 in accordance with vendor recommendations and best management practices, and in such a manner as to ensure full and continuous compliance with all applicable regulations.

   b) At least 60 days prior to the initial start-up date, prepare and submit to
the PSC and ARMA a Best Management Practices (BMP) Plan for the new limestone, gypsum, SAM control sorbent, and hydrated lime transfer, storage and distribution equipment listed in [CPCN 9087] Tables 1a-b and Table 2 that contains an explanation of reasonable precautions that will be used to prevent particulate matter from this equipment from becoming airborne. The Plan shall include a description of the types and frequency of inspections and/or preventative maintenance (PM) that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and PMs have been conducted as proposed. Completed

c) At least 60 days prior to replacing, elimination or in any manner changing any of the particulate control systems listed in [CPCN 9087] Table 1a-b and Table 2, GenOn shall submit a request to ARMA to amend the facility’s BMP Plan. The request shall specify the proposed change(s) in emissions control systems; shall demonstrate that the change(s) will not result in any increases in any pollutants; and update [CPCN 9087] Tables 1a-b and Table 2 of this CPCN. GenOn shall be authorized to make the changes proposed in the written request unless ARMA denies the request within 30 days of the receipt of the request.

1c.2 Testing Requirements:

[Reference: CPCN 9087: V. Testing]
17. In accordance with COMAR 26.11.01.04A, GenOn may be required by ARMA to conduct additional stack tests to determine compliance with applicable air quality requirements.

1c.3 Monitoring Requirements:

[Reference: CPCN 9087: VI. Monitoring]
18. GenOn shall operate continuous emissions monitoring system (CEMS) for SO₂, NOₓ and either oxygen or CO₂ as required under 40 CFR part 75 and continuous opacity monitoring systems (COMS) for Dickerson Units 1, 2 and 3.

See State Only requirements of COMAR 26.11.09.05C.

1c.4 Record Keeping Requirements:

[Reference: CPCN 9087: VII. Recordkeeping and Reporting]
24. All records and logs required by this CPCN shall be maintained at the facility for at least 5 years after the completion of the calendar year in which they were collected. These data shall be readily available for
1c.5 Reporting Requirements:

[Reference: CPCN 9087: VII. Recordkeeping and Reporting]

20. GenOn shall submit to ARMA and US EPA written reports of the results of all performance test conducted to demonstrate compliance with the standards set forth in applicable NSPS within 60 days of completion of the tests.

21. Final results of the performance tests required by this CPCN must be submitted to ARMA within 60 days after completion of the test. Analytical data shall be submitted to ARMA directly from the emission testing company.

25. All air quality notification and reports required by this CPCN shall be submitted to:

Administrator, Compliance Program
Air and Radiation Management Administration
1800 Washington Boulevard
Baltimore, Maryland 21230

26. All notification and reports required by 40 CFR 60 Subpart OOO and Subpart IIII and 40 CFR 63, unless specified otherwise, shall be submitted to:

Regional Administrator, US EPA
Region III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”

1d.0 Emissions Unit Number(s): SNCR Control System for D-1 D-2 and D-3

A Selective Non-Catalytic Reduction (SNCR) system is installed on Dickerson Units 1, 2, and 3. The SNCR system is to control NO\textsubscript{X} emissions. The SNCR system is a post combustion NO\textsubscript{X} reduction method through the controlled injection of Urea into the combustion gases of the boilers. The SNCR system consists of the following subsystems: 1. Reagent unloading and storage facilities; 2. Distribution and control.
Table IV – 1d – CPCN 9140: SNCR Control System

| modules; and 3. Two levels of wall injectors on each boiler. (Maryland’s Healthy Air Act (HAA) and the NO\textsubscript{X} Reduction and Trading Program). |

| 1d.1 Applicable Standards/Limits: |
| [Reference: CPCN 9140: II. Applicable Air Quality Regulations] |
| 9. The Dickerson facility is subject to all applicable, federally enforceable State air quality requirements including, but not limited to, the following regulations: |
| a) COMAR 26.11.01.10–Requires GenOn to install Continuous Opacity Monitoring (COM) systems to monitor opacity and Continuous Emissions Monitoring (CEM) systems (COMAR 26.11.01.11) to monitor SO\textsubscript{2}, NO\textsubscript{X} and either O\textsubscript{2} or CO\textsubscript{2} from each boiler, and to meet applicable CEM installation, certification, operating, monitoring, testing, and, malfunction requirements in 40 CFR Part 60, 40 CFR Part 75, and 40 CFR Part 51, Appendix P, §3.3-3.8 or §3.9 as incorporated by reference. |
| b) COMAR 26.11.03.18–Requires GenOn to update the existing Part 70 Operating Permit to include applicable SNCR Project requirements. |
| c) COMAR 26.11.06.02C(2)–Prohibits GenOn from causing or permitting the discharge of emissions from any installation or building (i.e., confined, non-fuel-burning equipment sources) other than water in an uncombined form, which are visible to human observers. |
| d) COMAR 26.11.06.03B(2)(a)–Prohibits GenOn from discharging into the outdoor atmosphere from any confined source particulate matter in excess of 0.03 grains per dry standard cubic feet (gr/scfd)(68.7 mg/dscm). |
| e) COMAR 26.11.06.03C(1)–Prohibits GenOn from causing or permitting emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne, |
| f) COMAR 26.11.06.03D–Prohibits GenOn from causing or permitting any material to be handled, transported, or stored, or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. |
| g) COMAR 26.11.09.03–When determining compliance with applicable particulate matter emission standards from boiler stacks (concentration requirement expressed as grains per standard cubic foot or milligrams per cubic meter of dry exhaust gas), GenOn shall correct to 50 percent excess air. |
| h) COMAR 26.11.09.05A(2)–Prohibits GenOn from causing or permitting the discharge of emissions from Dickerson Units 1, 2,and 3, other than water un an uncombined form, which are visible to the human observers. The visible emissions standard do not apply to emissions during startup and process modifications or adjustments, or occasional cleaning of |
control equipment, if (a) the visible emissions are not greater than 40% opacity; and (b) the visible emissions do not occur for more than 6 consecutive minutes in any 60-minute period.

i) COMAR 26.11.009.06B(3)-Prohibits GenOn from discharging particulate matter into the atmosphere caused by the combustion of solid fuel in Units 1, 2, and 3 in excess of 0.03 gr/dscf, corrected to 50% excess air.

j) COMAR 26.11.09.08C(2)(e)-Prohibits GenOn from discharging NO\textsubscript{X} emissions from Units 1, 2, and 3 in excess of 0.70 lb/MMBtu per hour of heat input.

k) COMAR 26.11.27-Requires GenOn to comply with the applicable emissions limitations for NO\textsubscript{X}, SO\textsubscript{2} and mercury, and the monitoring and record keeping requirements contained in COMAR 26.11.27.

11. GenOn shall limit the emissions of NO\textsubscript{X} from Units 1, 2 and 3 to 0.4 lb/MMBtu on an annual average basis (Phase II Acid Rain permit – 40 CFR §76.7(a)(1)).

### 1d.2 Testing Requirements:

[Reference: CPCN 9140: III. Monitoring and Testing Requirements]

14. GenOn shall conduct an initial stack emission test to measure NO\textsubscript{X} emissions from Units 1, 2 and 3 within 180 days of start-up of the SNCR system. Alternately, GenOn may request permission from MDE-ARMA to utilize the CEM required in Condition 12 for the initial emission test to measure NO\textsubscript{X}. **Completed**

15. At least 30 working days before initial stack tests for NO\textsubscript{X} are conducted, GenOn shall submit to MDE-ARMA a test protocol for review and approval. For any subsequent stack tests for NO\textsubscript{X}, GenOn shall either notify MDE-ARMA that the earlier approved protocol is to be used or shall submit a revised protocol for review and approval. **Completed**

16. Within 60 days of completing the stack tests for NO\textsubscript{X}, GenOn shall provide MDE-ARMA copies of the testing results. **Completed**

### 1d.3 Monitoring Requirements:

[Reference: CPCN 9140: III. Monitoring and Testing Requirements]

12. The common stack for Units 1, 2, and 3 shall be equipped with a continuous emissions monitoring system (CEMS) for NO\textsubscript{X} that is installed, calibrated, operated, and certified in accordance with 40 CFR Part 75.
13. Compliance with the visible emissions standards for Units 1, 2 and 3 shall be demonstrated by installation and operation of a continuous opacity monitor that is certified in accordance 40 CFR Part 60, Appendix B and that meets the quality assurance criteria of MDE-ARMA’s Air Management Administration Technical Memorandum 90-01, “Continuous Emission Monitoring (CEM) Policies and Procedures” (October 1990) (Performance Specification 2), provided the aforesaid Technical Memorandum is applicable and operative, unless and until GenOn is no longer required by law to monitor opacity continuously.

*See State Only requirements of COMAR 26.11.09.05C.*

<table>
<thead>
<tr>
<th>Table IV – 1d – CPCN 9140: SNCR Control System</th>
</tr>
</thead>
<tbody>
<tr>
<td>13. Compliance with the visible emissions standards for Units 1, 2 and 3 shall be demonstrated by installation and operation of a continuous opacity monitor that is certified in accordance 40 CFR Part 60, Appendix B and that meets the quality assurance criteria of MDE-ARMA’s Air Management Administration Technical Memorandum 90-01, “Continuous Emission Monitoring (CEM) Policies and Procedures” (October 1990) (Performance Specification 2), provided the aforesaid Technical Memorandum is applicable and operative, unless and until GenOn is no longer required by law to monitor opacity continuously.</td>
</tr>
</tbody>
</table>

**1d.4 Record Keeping Requirements:**

[Reference: CPCN 9140: IV. Recordkeeping and Reporting Requirements]

17. The following records related to operation of the SNCR on Units 1, 2 and 3, with supporting documentation, shall be maintained on site for at least five years and made available to MDE-ARMA upon request:

- a) Total NO\textsubscript{X} emissions (tons) for each calendar month separately for each Unit 1, 2 and 3.
- b) NO\textsubscript{X} emission rate, pounds per million Btu of heat input separately for each Unit 1, 2 and 3.
- c) All stack emission test reports.
- d) All CEM emission monitoring data.
- e) All CEM certification and calibration results; and
- f) Records of any repairs and maintenance made to the SNCR emission control device and CEM systems.

18. GenOn shall furnish written notification to MDE-ARMA of the following events related to the SNCR system for Units 1, 2 and 3:

- a) the date construction commenced within 30 days after such date.
- b) the anticipated project startup date, not more than 60 or less than 30 days prior to such date.
- c) the actual startup date within 15 days after such date; and
- d) the anticipated date of compliance stack testing at least 30 days prior to such date. *(Completed)*

19. All air quality records and logs required by this permit (CPCN 9140) shall be maintained at the facility for at least 5 years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of ARMA.
### Table IV – 1d – CPCN 9140: SNCR Control System

<table>
<thead>
<tr>
<th>1d.5</th>
<th>Reporting Requirements:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>[Reference: CPCN 9140: IV. Recordkeeping and Reporting Requirements]</td>
</tr>
<tr>
<td></td>
<td>20. All air quality notifications and reports required by this CPCN shall be submitted to:</td>
</tr>
<tr>
<td></td>
<td>Administrator, Compliance Program</td>
</tr>
<tr>
<td></td>
<td>Maryland Department of the Environment</td>
</tr>
<tr>
<td></td>
<td>Air and Radiation Management Administration</td>
</tr>
<tr>
<td></td>
<td>1800 Washington Boulevard</td>
</tr>
<tr>
<td></td>
<td>Baltimore, Maryland 21230</td>
</tr>
</tbody>
</table>

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”

---

**Please Note:** On June 29, 2015, the Supreme Court issued an opinion in *Michigan et al v. Environmental Protection Agency*. The Supreme Court's decision remands the MATS rule to EPA and returns the matter to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. As of the issuance of this permit, the MATS rule is in effect. The Supreme Court decision in *Michigan* requires the EPA to undertake additional proceedings for the limited purpose of evaluating costs for its “appropriate and necessary” finding which preceded the MATS rule. Until and unless the MATS rule is stayed and/or vacated by the D.C. Circuit, MATS related conditions in the Title V permit apply. If the MATS rule is stayed and/or vacated or partially stayed and/or vacated then the affected conditions in the Title V permit will be revised/removed accordingly.

### Table IV – 1e – MACT Subpart UUUUU

<table>
<thead>
<tr>
<th>1e.0</th>
<th>Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, &amp; 3-0003)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>1e.1</th>
<th>Applicable Standards/Limits:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Control of HAPs Emissions</td>
</tr>
</tbody>
</table>
Table IV – 1e – MACT Subpart UUUUU

<table>
<thead>
<tr>
<th>§63.9980 - What is the purpose of this subpart?</th>
</tr>
</thead>
<tbody>
<tr>
<td>This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.</td>
</tr>
</tbody>
</table>

| Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. |

<table>
<thead>
<tr>
<th>§63.9981 - Am I subject to this subpart?</th>
</tr>
</thead>
<tbody>
<tr>
<td>“You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart.”</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>§63.9984 - When do I have to comply with this subpart?</th>
</tr>
</thead>
<tbody>
<tr>
<td>“(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.”</td>
</tr>
<tr>
<td>“(c) You must meet the notification requirements in §63.10030 according to the schedule in §63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.”</td>
</tr>
<tr>
<td>“(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.”</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>§63.9991 - What emission limitations, work practice standards, and operating limits must I meet?</th>
</tr>
</thead>
<tbody>
<tr>
<td>“(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.</td>
</tr>
<tr>
<td>(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under §63.10009.</td>
</tr>
<tr>
<td>(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.</td>
</tr>
<tr>
<td>(b) As provided in §63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.</td>
</tr>
<tr>
<td>(c) You may use the alternate SO₂ limit in Tables 1 and 2 to this subpart only if your EGU:</td>
</tr>
<tr>
<td>(1) Has a system using wet or dry flue gas desulfurization technology and...</td>
</tr>
</tbody>
</table>
SO₂ continuous emissions monitoring system (CEMS) installed on the unit; and
(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with §63.10000(b).”

**Table IV – 1e – MACT Subpart UUUUU**

<table>
<thead>
<tr>
<th>If your EGU is in this subcategory...</th>
<th>For the following pollutants...</th>
<th>You must meet the following emission limits and work practice standards...</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5...</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Coal-fired unit not low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.³</td>
<td>Collect a minimum of 1 dscm per run. Please Note: PM CEMS will be used.</td>
</tr>
<tr>
<td></td>
<td>b. Sulfur dioxide (SO₂)²</td>
<td>2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.</td>
<td>SO₂ CEMS. Please Note: SO₂ will be used as a surrogate for HCl pursuant to §63.10000(c1)(v).</td>
</tr>
<tr>
<td></td>
<td>c. Mercury (Hg)</td>
<td>1.2E0 lb/TBtu or 1.3E-2 lb/GWh</td>
<td>Hg CEMS</td>
</tr>
</tbody>
</table>

¹For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
²Gross electric output.
³Incorporated by reference, see §63.14.
⁴You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

**General Compliance Requirements**

**§63.10000 - What are my general requirements for complying with this subpart?**

"(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance..."
“(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) Not Applicable.
(ii) Not Applicable.
(iii) Not Applicable.

(iv) If your coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO$_2$) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO$_2$ emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(A) Not Applicable.
(B) Not Applicable.

“(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that
Table IV – 1e – MACT Subpart UUUUU

apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of §63.10010. Using the process described in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section. (d)(4) You must operate and maintain the CMS according to the site-specific monitoring plan.” Note: The SO₂ monitoring plan was prepared under 40 CFR Part 75. The monitoring plans for the PEMS and Hg CEMS were submitted to the Department and EPA in October 2014.

“(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to §63.10021(e).”  
“(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distribution system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR Part 60, Subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.”

“(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be
or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

(l) On or before the date an EGU is subject to this subpart, you must install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.”

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards
As stated in §§63.9991, you must comply with the following applicable work practice standards:

<table>
<thead>
<tr>
<th>If your EGU is...</th>
<th>You must meet the following...</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. An existing EGU</td>
<td>Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).</td>
</tr>
<tr>
<td>3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup</td>
<td>You have the option of complying using either of the following work practice standards. (1) If you choose to comply using paragraph (1) of the definition of “startup” in §63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in §63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified...</td>
</tr>
</tbody>
</table>
### Table IV – 1e – MACT Subpart UUUUU

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>in §63.10011(g) and §63.10021(h) and (i).</td>
<td></td>
</tr>
<tr>
<td>(2) If you choose to comply using paragraph (2) of the definition of “startup” in §63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.</td>
<td></td>
</tr>
<tr>
<td>For startup of an EGU, you must use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in §63.10020(e).</td>
<td></td>
</tr>
<tr>
<td>Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits within 4 hours of start of electricity generation. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.</td>
<td></td>
</tr>
<tr>
<td>You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.</td>
<td></td>
</tr>
<tr>
<td>… You must collect monitoring data during startup periods, as specified in §63.10020(a) and (e). You must keep records during startup periods, as provided in §§63.10032 and 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. You must provide reports concerning activities and startup periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.</td>
<td></td>
</tr>
<tr>
<td>4. <strong>A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown</strong></td>
<td>You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices.</td>
</tr>
</tbody>
</table>
Table IV – 1e – MACT Subpart UUUUU

If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible.

You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in §63.10020(a). You must keep records during shutdown periods, as provided in §§63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.

1e.2 **Testing Requirements:**

**Control of HAPs Emissions**

**Testing and Initial Compliance Requirements**

§63.10005 - What are my initial compliance requirements and by what date must I conduct them?

(a) **General requirements.** For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to §63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in §63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission
Table IV – 1e – MACT Subpart UUUU

| Limit, you must collect hourly electrical load data during the test period. (2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e., an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO₂ or PM CEMS, the initial performance test consists of 30- (or, if emissions averaging for Hg is used, 90-) boiler operating days of data collected by the initial compliance demonstration date specified in §63.9984(f) with the certified monitoring system. Pollutant emission rates measured during startup periods and shutdown period (as defined in §63.10042) are not to be included in the compliance demonstration, except as otherwise provided in §63.10000(c)(1)(vi)(B) and paragraph (a)(2)(iii) of this section. (i) The 30- (or, if applicable, 90-) boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO₂ emissions limit in Table 1 or 2 to this subpart. (ii) You must collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO₂, O₂, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with an electrical output-based emission limit, you must also collect hourly electrical load data during the performance test period. (iii) For a group of affected units that are in the same subcategory, are subject to the same emission standards, and share a common stack, if you elect to demonstrate compliance by monitoring emissions at the common stack, startup and shutdown emissions (if any) that occur during the 30-(or, if applicable, 90-) boiler operating day performance test must either be excluded from or included in the compliance demonstration as follows: (A) If one of the units that shares the stack either starts up or shuts down at a time when none of the other units is operating, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; (B) If all units that are currently operating are in the startup or shutdown mode, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; or (C) If any unit starts up or shuts down at a time when another unit is operating, and the other unit is not in the startup or shutdown mode, you must include all pollutant emission rates measured during the startup or shutdown period in the compliance demonstrations. (b) Performance testing requirements: If you choose to use performance |
testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to §63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in §63.9984, provided that the following conditions are fully met:

1. For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in §63.9984;
2. For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;
3. The performance test was conducted in accordance with all applicable requirements in §63.10007 and Table 5 to this subpart;
4. A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and
5. For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) Not Applicable.

(d) CMS requirements. If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

1. For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable \( \text{SO}_2 \), HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an \( \text{SO}_2 \), HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured

| Table IV – 1e – MACT Subpart UUUUU | testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to §63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in §63.9984, provided that the following conditions are fully met:
1. For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in §63.9984;
2. For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;
3. The performance test was conducted in accordance with all applicable requirements in §63.10007 and Table 5 to this subpart;
4. A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and
5. For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.
(c) Not Applicable.
(d) CMS requirements. If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.
1. For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable \( \text{SO}_2 \), HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an \( \text{SO}_2 \), HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured |
Table IV – 1e – MACT Subpart UUUUU

| CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO₂, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (NOTE: For this calculation, the term \( E_{hi} \) in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart). |

(2) Not Applicable.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.”

“(e) Tune-ups. All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to §63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in §63.9984 and according to the applicable provisions in §63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.”

(h) Not Applicable.

“(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in §63.10030.”

§63.10006 - When must I conduct subsequent performance tests or tune-ups?

“(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an
applicable emission limit as provided for under §63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and §63.10007 at least every year.”

“(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, §63.10007, and §63.10000(c), except as otherwise provided in §63.10021(d)(1).”

“(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in §63.10021(d)(1).”

“(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in §63.10031.”

**Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements**

As stated in §63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:¹

<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant...</th>
<th>Using...</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit...</th>
<th>Using²...</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Filterable Particulate matter (PM)</td>
<td>PM CEMS</td>
<td>a. Install, certify, operate, and maintain the PM CEMS Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems Part 75 of this chapter and §§63.10010(a), (b), (c), and (d).</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or</td>
<td></td>
</tr>
<tr>
<td>3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)</td>
<td>HCl and/or HF CEMS</td>
<td>a. Install, certify, operate, and maintain the HCl or HF CEMS</td>
<td>Appendix B of this subpart.</td>
</tr>
<tr>
<td>-----------------------------------------------------</td>
<td>-------------------</td>
<td>-----------------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §§63.10010(a), (b), (c), and (d).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).</td>
</tr>
</tbody>
</table>

Please Note: SO₂ will be used as a surrogate for HCl pursuant to §63.10000(c1)(v). See #5 SO₂ CEMS

<table>
<thead>
<tr>
<th>4. Mercury (Hg)</th>
<th>Hg CEMS</th>
<th>a. Install, certify, operate, and maintain the CEMS</th>
<th>Sections 3.2.1 and 5.1 of Appendix A of this subpart.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §§63.10010(a), (b), (c), and (d).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates</td>
<td>Section 6 of Appendix A to this subpart.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>5. Sulfur dioxide (SO₂)</th>
<th>SO₂CEMS</th>
<th>a. Install, certify, operate, and maintain the CEMS</th>
<th>Part 75 of this chapter and §§63.10010(a) and (f).</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §§63.10010(a), (b), (c), and (d).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBu</td>
<td>Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).</td>
</tr>
</tbody>
</table>
NRG Energy, Inc  
Dickerson Generating Station  
21200 Martinsburg Road, Dickerson, Maryland 20842  
Part 70 Operating Permit No. 24-031-0019

Table IV – 1e – MACT Subpart UUUUU

<table>
<thead>
<tr>
<th>or lb/MWh emissions rates</th>
<th>emissions rate and electrical output data (see §63.10007(e)).</th>
</tr>
</thead>
</table>

1 Regarding emissions data collected during periods of startup or shutdown, see §§63.10020(b) and (c) and §63.10021(h).
2 See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
3 Incorporated by reference, see §63.14.
4 When using ASTM D6348-03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (2) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%R) must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤ %R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: 

\[ \text{Reported Result} = \left( \frac{\text{Measured Concentration in Stack}}{\%R} \right) \times 100 \]

§63.10007 - What methods and other procedures must I use for the performance tests?

“(a) Except as otherwise provided in this section, you must conduct all required performance tests according to §63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(1) If you use CEMS (Hg, HCl, SO₂, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run
stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) Not Applicable.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO\(_2\) ppm by \(1.66 \times 10^{-7}\);  
(ii) Multiply HCl ppm by \(9.43 \times 10^{-8}\);  
(iii) Multiply HF ppm by \(5.18 \times 10^{-8}\);  
(iv) Multiply HAP metals concentrations (mg/dscm) by \(6.24 \times 10^{-8}\); and  
(v) Multiply Hg concentrations (µg/scm) by \(6.24 \times 10^{-11}\).

(3) To determine compliance with emission limits expressed in lb/MWh or
lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with $1.66 \times 10^{-7}$ lb/scf-ppm for SO$_2$, $9.43 \times 10^{-8}$ lb/scf-ppm for HCl (if an HCl CEMS is used), $5.18 \times 10^{-8}$ lb/scf-ppm for HF (if an HF CEMS is used), or $6.24 \times 10^{-8}$ lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining $C_h$ as the average SO$_2$, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the $10^3$ term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO$_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

(1) **Diluent cap values.** If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO$_2$ concentration is below the cap value or the measured O$_2$ concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for CO$_2$ or 19% for O$_2$.

(ii) For all other EGUs, you may use 5% for CO$_2$ or 14% for O$_2$.

(2) **Default electrical load.** If you use CEMS to continuously monitor Hg, HCl, HF, SO$_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, this default value is not considered to be substitute data.

For a startup or shutdown hour in which there is heat input to an affected EGU but zero electrical load, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable electrical
Table IV – 1e – MACT Subpart UUUUU

output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter. This default electrical load is either the nameplate capacity of the EGU or the highest electrical load observed in at least four representative quarters of EGU operation. For a monitored common stack, the default electrical load is used only when all EGUs are operating (i.e., combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default electrical load equal to 5% of the combined maximum sustainable electrical load of the EGUs that are operating but have a total of zero electrical load must be used to calculate the hourly electrical output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.”

1e.3 Monitoring Requirements:

Control of HAPs Emissions

§ 63.10010 - What are my monitoring, installation, operation, and maintenance requirements?

“(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) Single unit-single stack configurations. For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) Unit utilizing common stack with other affected unit(s). When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.”

“(4) Unit with a main stack and a bypass stack. If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not
Table IV – 1e – MACT Subpart UUUUU

| feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.”

“(b) If you use an oxygen (O\textsubscript{2}) or carbon dioxide (CO\textsubscript{2}) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O\textsubscript{2} or CO\textsubscript{2} concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O\textsubscript{2} or CO\textsubscript{2} data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from §75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) Not Applicable.

(f)(1) If you use an SO\textsubscript{2} CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO\textsubscript{2} CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO\textsubscript{2} CEMS has a span value of 30 ppm or less.
(3) Calculate and record a 30-boiler operating day rolling average SO₂ emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO₂ emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default electrical load and the diluent cap are available for use in the hourly SO₂ emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO₂ emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) Not Applicable.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ±14 °C (320° ±25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu,
(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) Not Applicable.
Table IV – 1e – MACT Subpart UUUUU

<table>
<thead>
<tr>
<th>§63.10011</th>
<th>How do I demonstrate initial compliance with the emissions limits and work practice standards?</th>
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</thead>
<tbody>
<tr>
<td>(a)</td>
<td>You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.</td>
</tr>
<tr>
<td>(b)</td>
<td>Not Applicable.</td>
</tr>
<tr>
<td>(c)(1)</td>
<td>If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with certified CEMS after the applicable date in §63.9984 (or, if applicable, prior to that date, as described in §63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.</td>
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<tr>
<td>(2)</td>
<td>For a unit that uses a CEMS to measure SO₂ or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in §63.9984 (or, if applicable, prior to that date, as described in §63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO₂ or filterable PM emission limit in Table 1 or 2 to this subpart.</td>
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“(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to §63.10030(e). |

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown. |

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account. |

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU. |

(1) You may use the diluent cap and default electrical load values, as described in §63.10007(f), during startup periods or shutdown periods. |

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods. |

(3) You must report the information as required in §63.10031. |

(4) If you choose to use paragraph (2) of the definition of “startup” in §63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of “startup” in §63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.
Table IV – 1e – MACT Subpart UUUUU

(i) As mentioned in §63.6(g)(1), the request will be published in the FEDERAL REGISTER for notice and comment rulemaking. Until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in §63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard.

(ii) The request need not address the items contained in §63.6(g)(2).

(iii) The request shall provide evidence of a documented manufacturer-identified safety issue.

(iv) The request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, the request shall contain documentation that:
(A) The EGU is using clean fuels to the maximum extent possible to bring the EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in the EGU;
(B) The EGU has explicitly followed the manufacturer’s procedures to alleviate or prevent the identified safety issue; and
(C) Identifies with specificity the details of the manufacturer’s statement of concern.

(vi) The request shall specify the other work practice standards the EGU owner or operator will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.”

Continuous Compliance Requirements

§63.10020 - How do I monitor and collect data to demonstrate continuous compliance?

“(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10000(d).
(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.
(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

(e) Additional requirements during startup periods and shutdown periods
(1) During each period of startup, you must record for each EGU:
   (i) The date and time that clean fuels being combusted for the purpose of startup begins;
   (ii) The quantity and heat input of clean fuel for each hour of startup;
   (iii) The electrical load for each hour of startup;
   (iv) The date and time that non-clean fuel combustion begins; and
   (v) The date and time that clean fuels being combusted for the purpose of startup ends.
(2) During each period of shutdown, you must record for each EGU:
   (i) The date and time that clean fuels being combusted for the purpose of shutdown begins;
   (ii) The quantity and heat input of clean fuel for each hour of shutdown;
   (iii) The electrical load for each hour of shutdown;
   (iv) The date and time that non-clean fuel combustion ends; and
   (v) The date and time that clean fuels being combusted for the purpose of shutdown ends.
(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10011(l).
   (i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS you must:
      (A) Record temperature and flow rate of post-combustion (exhaust) gas and amperage of forced draft fan(s) upstream of each filterable PM control device during each hour of startup.
Table IV – 1e – MACT Subpart UUUU

(B) Record temperature and flow rate of exhaust gas and amperage of induced draft fan(s) downstream of each filterable control device during each hour of startup.
(C) Not Applicable.
(D) Not Applicable.
(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to fuel ratio and the differential pressure of the liquid during each hour of startup.

§63.10021 - How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
“(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.
(b) Except as otherwise provided in §63.10020(c), if you use a CEMS to measure $SO_2$, $PM$, $HCl$, $HF$, or $Hg$ emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, $CO_2$, $O_2$, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

$$\bar{E}_{avg} = \frac{\sum_{i=1}^{n} E_i}{n} \quad (Eq. 8)$$

Where:
Her, $i$ is the hourly emissions rate for hour $i$ and $n$ is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

“(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of §63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.
(1) As applicable, inspect the burner and combustion controls, and clean
or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO\textsubscript{X} and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO\textsubscript{X} and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate wind box pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O\textsubscript{2} probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO\textsubscript{X}. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO\textsubscript{X} optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load,
measure the concentration in the effluent stream of CO and NO\textsubscript{X} in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO\textsubscript{X} and O\textsubscript{2} monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO\textsubscript{X} in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in §63.10030) and electronically (as specified in §63.10031). Report the date of each subsequent tune-up electronically (as specified in §63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with §63.10031.”

“(f) You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA’s Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA’s Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.

(g) You must report each instance in which you did not meet an applicable

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<tr>
<th>Table IV – 1e – MACT Subpart UUUUUU</th>
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<tbody>
<tr>
<td>measure the concentration in the effluent stream of CO and NO\textsubscript{X} in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO\textsubscript{X} and O\textsubscript{2} monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;</td>
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<td>(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:</td>
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<td>(i) The concentrations of CO and NO\textsubscript{X} in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;</td>
</tr>
<tr>
<td>(ii) A description of any corrective actions taken as a part of the combustion adjustment; and</td>
</tr>
<tr>
<td>(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and</td>
</tr>
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<td>(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with §63.10031.”</td>
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“(f) You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA’s Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA’s Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.

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Table IV – 1e – MACT Subpart UUUUU

<table>
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<tr>
<th>Emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.</th>
</tr>
</thead>
<tbody>
<tr>
<td>(h) You must keep records as specified in §63.10032 during periods of startup and shutdown.</td>
</tr>
<tr>
<td>(1) You may use the diluent cap and default electrical load values, as described in §63.10007(f), during startup periods or shutdown periods.</td>
</tr>
<tr>
<td>(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.</td>
</tr>
<tr>
<td>(3) You must report the information as required in §63.10031.</td>
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<tr>
<td>(4) You may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in §63.10042.</td>
</tr>
<tr>
<td>(i) You must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown.”</td>
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Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in §63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

<table>
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<tr>
<th>If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards...</th>
<th>You demonstrate continuous compliance by...</th>
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<tbody>
<tr>
<td>1. CEMS to measure filterable PM, SO₂, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg</td>
<td>Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.</td>
</tr>
<tr>
<td>5. Conducting periodic performance tune-ups of your EGU(s)</td>
<td>Conducting periodic performance tune-ups of your EGU(s), as specified in §63.10021(e).</td>
</tr>
<tr>
<td>6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU(s) during startup</td>
<td>Operating in accordance with Table 3.</td>
</tr>
<tr>
<td>7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU(s) during startup</td>
<td>Operating in accordance with Table 3.</td>
</tr>
</tbody>
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Table IV – 1e – MACT Subpart UUUUU

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<th>or solid oil-derived fuel-fired EGU during shutdown</th>
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1e.4 **Record Keeping Requirements:**

**Note:** All records must be maintained for a period of 5 years. [Reference: COMAR 26.11.03.06C(5)(g)]

Control of HAPs Emissions

**Notification, Reports, and Records**

§63.10032 - What records must I keep?

“(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.”

(2) **Not Applicable**.

(3) **Not Applicable**.

“(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each
malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.”

§63.10033 - In what form and how long must I keep my records?
“(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).
(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.”

1e.5 Reporting Requirements:

Control of HAPs Emissions
Notification, Reports, and Records
§63.10030 - What notifications must I submit and when?
“(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.
(b) As specified in §63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.”
“(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.
(e) When you are required to conduct an initial compliance demonstration as specified in §63.10011(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.
(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the
Table IV – 1e – MACT Subpart UUUUUU

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<td>fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.</td>
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<tr>
<td>(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.</td>
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<tr>
<td>(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.</td>
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<tr>
<td>(4) Identification of whether you plan to demonstrate compliance by emissions averaging.</td>
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<td>(5) A signed certification that you have met all applicable emission limits and work practice standards.</td>
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<tr>
<td>(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification and the cause of the deviation in the Notification of Compliance Status report.</td>
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<td>(7) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following:</td>
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<td>(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with §63.10006(b), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in §63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.</td>
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<tr>
<td>(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:</td>
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<tr>
<td>(A) “This EGU complies with the requirements in §63.10021(a) to demonstrate continuous compliance.” and</td>
<td></td>
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<tr>
<td>(B) “No secondary materials that are solid waste were combusted in any affected unit.”</td>
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<td>“(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of “startup” in §63.10042.</td>
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<td>(i) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you shall include a report that identifies:</td>
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<tr>
<td>(A) The original EGU installation date;</td>
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<tr>
<td>(B) The original EGU design characteristics, including, but not limited to, fuel and PM controls;</td>
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Table IV – 1e – MACT Subpart UUUUU

| (C) Each design PM control device efficiency; |
| (D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour; |
| (E) The design time from start of fuel combustion to necessary conditions for each PM control device startup; |
| (F) Each design PM control device efficiency upon startup of the PM control device; |
| (G) The design EGU uncontrolled PM emission rate in terms of pounds PM per hour; |
| (H) Each change from the original design that did or could have changed PM emissions, including, but not limited to, each different fuel mix, each revision to each PM control device, and each EGU revision, along with the month and year that the change occurred; |
| (I) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls; |
| (J) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour; |
| (K) Current PM control device efficiency from each PM control device; |
| (L) Current time from start of fuel combustion to conditions necessary for each PM control device startup; |
| (M) Current PM control device efficiency upon startup of each PM control device; and |
| (N) Current EGU uncontrolled PM emission rate in terms of pounds PM per hour. |

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located. Apart from preparing, signing, and sealing this report, the professional engineer shall be independent and not otherwise employed by your company, any parent company of your company, or any subsidiary of your company.”

§63.10031 - What reports must I submit and when?

“(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.9984 and
**Table IV – 1e – MACT Subpart UUUUUU**

ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to §63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 (or 48) months and was delayed until the next scheduled unit shutdown.

(5) For each instance of startup or shutdown:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of §63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of §63.10020(e).
(iii) If you choose to use CEMS for compliance purposes, include hourly average CEMS values and hourly average flow rates. Use units of milligrams per cubic meter for PM CEMS, micrograms per cubic meter for Hg CEMS, and ppmv for HCl, HF, or SO₂ CEMS. Use units of standard cubic meters per hour on a wet basis for flow rates.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in §63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) On or after April 16, 2017, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to,
Table IV – 1e – MACT Subpart UUUUU

| flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

1. On or after **April 16, 2017**, within 60 days after the date of completing each CEMS (SO₂, PM, HCl, HF, and Hg) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in §63.2 and as required in this chapter.

2. On or after **April 16, 2017**, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

3. Reports for an SO₂ CEMS, a Hg CEMS or sorbent trap monitoring
system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and §63.10021(f).

(4) On or after April 16, 2017, submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

(6) Prior to April 16, 2017, all reports subject to electronic submittal in paragraphs (f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

(i) The facility name, physical address, mailing address (if different from the physical address), and county;
(ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;
(iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;
(iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;
(v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;
(vi) The identification of each emission point to which the report applies.

<table>
<thead>
<tr>
<th>Table IV – 1e – MACT Subpart UUUUU</th>
</tr>
</thead>
<tbody>
<tr>
<td>system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and §63.10021(f).</td>
</tr>
<tr>
<td>(4) On or after April 16, 2017, submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (<a href="http://www.epa.gov/cdx">www.epa.gov/cdx</a>). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.</td>
</tr>
<tr>
<td>(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.</td>
</tr>
<tr>
<td>(6) Prior to April 16, 2017, all reports subject to electronic submittal in paragraphs (f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:</td>
</tr>
<tr>
<td>(i) The facility name, physical address, mailing address (if different from the physical address), and county;</td>
</tr>
<tr>
<td>(ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;</td>
</tr>
<tr>
<td>(iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;</td>
</tr>
<tr>
<td>(iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;</td>
</tr>
<tr>
<td>(v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;</td>
</tr>
<tr>
<td>(vi) The identification of each emission point to which the report applies.</td>
</tr>
</tbody>
</table>
An “emission point” is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., “Unit 2 stack,” “common stack CS001,” or “multiple stack MS001”);

(vii) The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;

(viii) The pollutant(s) being addressed in the report;

(ix) The reporting period being covered by the report (if applicable);

(x) The relevant test method that was performed for a performance test (if applicable);

(xi) The date the performance test was conducted (if applicable); and

(xii) The responsible official’s name, title, and phone number.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.”

### Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

As stated in §63.10031, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>You must submit a...</th>
<th>The report must contain...</th>
<th>You must submit the report...</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Compliance report</td>
<td>a. Information required in §63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.10031(d). If there were periods during which the CMSs, including continuous...</td>
<td>Semiannually according to the requirements in §63.10031(b).</td>
</tr>
</tbody>
</table>
Table IV – 1e – MACT Subpart UUUUU

| emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.10031(e) |

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”

<table>
<thead>
<tr>
<th>Table IV – 2</th>
</tr>
</thead>
</table>

**2.0 Emissions Unit Number(s): DCT-1: Combustion Turbine**

One (1) Pratt and Whitney FT4-A combustion turbine rated at 18 megawatts, fires No.2 fuel oil and utilized for black start and peaking service. [4-0907]

**2.1 Applicable Standards/Limits:**

A. Control of Visible Emissions

**COMAR 26.11.09.05A(2) & (3) – Fuel Burning Equipment**

“Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity”.

**Exceptions.** Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period.”

B. Control of Sulfur Oxides

**COMAR 26.11.09.07A(2) - Sulfur Content Limitations for Fuel.**

“A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III and IV:

(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent.”

C. Control of Nitrogen Oxides

**COMAR 26.11.09.08G - Requirements for Fuel-Burning Equipment with a**
Table IV – 2

<table>
<thead>
<tr>
<th>Description</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Factor of 15 Percent or Less, and Combustion Turbines with a</td>
<td>Capacity Factor Greater than 15 Percent.</td>
</tr>
<tr>
<td>(“1) A person who owns or operates fuel-burning equipment with a capacity</td>
<td>factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:</td>
</tr>
<tr>
<td>factor shall:</td>
<td>(a) Provide certification of the capacity factor of the equipment to the</td>
</tr>
<tr>
<td>(a) Provide certification of the capacity factor of the equipment to the</td>
<td>Department in writing;</td>
</tr>
<tr>
<td>Department in writing;</td>
<td>(b) For fuel-burning equipment that operates more than 500 hours during</td>
</tr>
<tr>
<td>(b) For fuel-burning equipment that operates more than 500 hours during</td>
<td>a calendar year, perform a combustion analysis and optimize combustion</td>
</tr>
<tr>
<td>a calendar year, perform a combustion analysis and optimize combustion</td>
<td>at least once annually;</td>
</tr>
<tr>
<td>at least once annually;</td>
<td>(c) Maintain the results of the combustion analysis at the site for at</td>
</tr>
<tr>
<td>(c) Maintain the results of the combustion analysis at the site for at</td>
<td>least 2 years and make these results available to the Department and the</td>
</tr>
<tr>
<td>least 2 years and make these results available to the Department and the</td>
<td>EPA upon request;</td>
</tr>
<tr>
<td>EPA upon request;</td>
<td>(d) Not applicable; and</td>
</tr>
<tr>
<td>(d) Not applicable; and</td>
<td>(e) Not applicable.”</td>
</tr>
</tbody>
</table>

2.2 Testing Requirements:

A. Control of Visible Emissions:
   See Monitoring Requirements.

B. Control of Sulfur Oxides:
   See Monitoring Requirements.

C. Control of Nitrogen Oxides:
   The Permittee, if the turbines operate more than 500 hours, shall perform a combustion analysis and optimize combustion at least once annually. [Reference: COMAR 26.11.09.08G(1)(b)].

2.3 Monitoring Requirements:

A. Control of Visible Emissions
   The Permittee shall verify that there are no visible emissions when operating. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period at least once every 168 hours of operation. If the turbine operates less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived. The Permittee shall perform the following, if emissions are visible to human observer:
   (a) inspect combustion control system and combustion turbine operations,
   (b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and
   (c) document in writing the results of inspections, adjustments and/or
repairs to the combustion turbine.
(d) after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform a Method 9 observation once daily when combustion turbine is operating for 18 minutes until corrective action have eliminated visible emissions.

[Reference: COMAR 26.11.03.06C]

B. Control of Sulfur Oxides:
The Permittee shall obtain a certification from the fuel supplier indicating that the oil complies with the limitation on the sulfur content of the fuel oil

[Reference: COMAR 26.11.03.06C]

C. Control of Nitrogen Oxides:
See Record Keeping Requirements.

2.4 Record Keeping Requirements:
Note: All records must be maintained for a period of at least 5 years.

[Reference: COMAR 26.11.03.06C(5)(g)]

A. Control of Visible Emissions
The Permittee shall maintain a copy of the visible emissions readings on site for at least five years and make available to the Department upon request. [Reference: COMAR 26.11.03.06C]

B. Control of Sulfur Oxides:
The Permittee shall maintain records of fuel supplier’s certification on site for at least five years and shall make records available to the Department upon request. [Reference: COMAR 26.11.03.06C]

C. Control of Nitrogen Oxides
The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. The Permittee shall maintain records if the calculations of the capacity factors. [Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]

2.5 Reporting Requirements:

A. Control of Visible Emissions:
The Permittee shall report incidents of visible emissions in accordance with permit condition 4, Section III. Plant Wide Conditions, “Report of Excess Emissions and Deviations”. [Reference: COMAR 26.11.03.06C]
Table IV – 2

B. Control of Sulfur Oxides:
The Permittee shall report fuel supplier certifications to the Department upon request. [Reference: COMAR 26.11.09.07C]

C. Control of Nitrogen Oxides
The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with the support documentation in the Annual Emission Certification Report. [Reference: COMAR 26.11.09.08G(1)(a) COMAR 26.11.03.06C].

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”

Table IV – 3

3.0 Emissions Unit Number(s): H CT-1 & H CT-2: Combustion Turbines Cont’d

Two (2) General Electric Frame 7F combustion turbines each with a nominal rated capacity of 167 megawatts located at Station H. These combustion turbines fire primarily natural gas and No. 2 fuel oil as a secondary fuel. The units are equipped with inlet foggers to maintain output at high ambient temperatures and with water injection to control NOX emissions. [9-0362 & 9-0363]

3.1 Applicable Standards/Limits:

A. Control of Visible Emissions
COMAR 26.11.09.05A(2) & (3) – Fuel Burning Equipment
“Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity”.

Exceptions. Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:
(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period.”
### Table IV – 3

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>B. Control of Sulfur Oxides</strong></td>
<td></td>
</tr>
<tr>
<td>1. PSD Approval</td>
<td>CPCN Order No. 68851 Case No. 8063 condition 27 which limits sulfur in fuel content to no more than 0.3% sulfur, by weight.</td>
</tr>
<tr>
<td></td>
<td>CPCN Order No. 68851 Case No. 8063 conditions 17 and 18 which limits sulfur emissions to 34 pounds per hour per combustion turbine when firing natural gas and 579 pounds per hour when firing distillate fuel oil. Total annual emissions of SO₂ from the two turbines are limited to 1249 tons in any consecutive 12-month period.</td>
</tr>
<tr>
<td>2. NSPS Subpart GG</td>
<td><strong>40 CFR §60.333</strong> which limits sulfur in fuel content to 0.8%.</td>
</tr>
<tr>
<td>3. Acid Rain Permit</td>
<td>The Permittee shall comply with the requirements of the renewal Phase II Acid Rain Permit issued in conjunction with this Part 70 permit. The Acid Rain Permit is attached to the permit in Appendix A.</td>
</tr>
<tr>
<td>4. Cross-State Air Pollution Rule</td>
<td><strong>TR SO₂ Group 1 Trading Program 40 CFR Part 97 Subpart CCCCC</strong> The Permittee shall comply with the provisions and requirements of §97.601 through §97.635</td>
</tr>
</tbody>
</table>

**Note:** §97.606(c) SO₂ emissions requirements. For TR SO₂ Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all TR SO₂ Group 1 units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO₂ Group 1 allowance transfer must be submitted for recordation in a TR SO₂ Group 1 source's compliance account in order to be available for use in complying with the source's TR SO₂ Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624.
### Table IV – 3

<table>
<thead>
<tr>
<th>C. Control of Nitrogen Oxides</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. NO&lt;sub&gt;x&lt;/sub&gt; RACT</td>
</tr>
<tr>
<td><strong>COMAR 26.11.09.08G.</strong> - Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 Percent or Less, and Combustion Turbines with a Capacity Factor Greater than 15 Percent.</td>
</tr>
<tr>
<td>“(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:</td>
</tr>
<tr>
<td>(a) Provide certification of the capacity factor of the equipment to the Department in writing;</td>
</tr>
<tr>
<td>(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;</td>
</tr>
<tr>
<td>(c) Maintain the results of the combustion analysis at the site for at least 2 years and make these results available to the Department and the EPA upon request;</td>
</tr>
<tr>
<td>(d) Not applicable and</td>
</tr>
<tr>
<td>(e) Not applicable.</td>
</tr>
<tr>
<td>(2) A person who owns or operates a combustion turbine with a capacity factor greater than 15 percent shall meet an hourly average NO&lt;sub&gt;x&lt;/sub&gt; emission rate of not more than 42 ppm when burning gas or 65 ppm when burning oil (dry volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive.”</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2. PSD Limitation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CPCN Order No. 68851 Case No. 8063 condition 15</strong> which limits NO&lt;sub&gt;x&lt;/sub&gt; emissions to no more than 42 parts per million dry (ppmvd) at 15 percent O&lt;sub&gt;2&lt;/sub&gt; when firing natural gas. When firing No. 2 fuel oil, emissions, in ppmvd at 15 percent O&lt;sub&gt;2&lt;/sub&gt; will be limited to no more than:</td>
</tr>
<tr>
<td>57 for N ≤ 0.015</td>
</tr>
<tr>
<td>and</td>
</tr>
<tr>
<td>57 + 400N for N &gt; 0.015</td>
</tr>
<tr>
<td>where N is the nitrogen content of the fuel in percent by weight.</td>
</tr>
<tr>
<td><strong>CPCN Order No. 68851 Case No. 8063 condition 17 and 18</strong> which limits NO&lt;sub&gt;x&lt;/sub&gt; emissions from each combustion turbine to 321 pounds per hour when firing natural gas and 608 pounds per hour when firing distillate fuel oil. Total annual emissions of NO&lt;sub&gt;x&lt;/sub&gt; from the two turbines are limited to 1311 tons per consecutive 12-month period.</td>
</tr>
<tr>
<td><strong>CPCN Order No. 68851 Case No. 8063 condition 26</strong> which limits the annual average nitrogen content of the fuel oil burned in the combustion turbines to not more than 0.05%, by weight.</td>
</tr>
</tbody>
</table>
3. NSPS Subpart GG

**40 CFR §60.332** - Standard for nitrogen oxides.

“No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere a from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

\[
STD = (0.0075 \times (14.4/Y)) + F
\]

Where:

- **STD** = allowable NO\(_X\) emissions (percent by volume at 15 percent oxygen and on a dry basis)
- **Y** = manufacturer’s rated heat rate at manufacturer’s rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of **Y** shall not exceed 14.4 kilojoules per watt hour.
- **F** = NO\(_X\) emission allowance for fuel-bound nitrogen as defined in 40 CFR §60.332(a)(3):

<table>
<thead>
<tr>
<th>Fuel-Bound Nitrogen (percent by weight)</th>
<th>F (NO(_X) percent by volume)</th>
</tr>
</thead>
<tbody>
<tr>
<td>N &lt; 0.015</td>
<td>0</td>
</tr>
<tr>
<td>0.015 &lt; N &lt; 0.1</td>
<td>0.04(N)</td>
</tr>
<tr>
<td>0.1 &lt; N &lt; 0.25</td>
<td>0.004 + 0.0067(N – 0.1)</td>
</tr>
<tr>
<td>N &gt; 0.25</td>
<td>0.005</td>
</tr>
</tbody>
</table>

4. Acid Rain Permit

These units are not subject to a NO\(_X\) limitation under Acid Rain because they are not coal-fired. However, the Permittee is required to comply with the continuous NO\(_X\) monitoring requirement of 40CFR Part 75 and associated record keeping and reporting requirements. **[Reference: Acid Rain Permit, 40 CFR 75 subpart G]**

5. Cross-State Air Pollution Rule

**TR NO\(_X\) Annual Trading Program 40 CFR Part 97 Subpart AAAAA**

The Permittee shall comply with the provisions and requirements of §97.401 through §97.435

**Note: §97.406(c) NO\(_X\) emissions requirements.** For TR NO\(_X\) Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\(_X\) Annual source and each TR NO\(_X\) Annual unit at the source shall hold, in the source's compliance account, TR NO\(_X\) Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NO\(_X\) emissions for such control period from all TR NO\(_X\) Annual units at the source.
Table IV – 3

| **Allowance transfer deadline means, for a control period in a given year,** midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NOx Annual allowance transfer must be submitted for recordation in a TR NOx Annual source's compliance account in order to be available for use in complying with the source's TR NOx Annual emissions limitation for such control period in accordance with §§97.406 and 97.424. |

| **TR NOx Ozone Season Trading Program 40 CFR Part 97 Subpart BBBBB** |
| The Permittee shall comply with the provisions and requirements of §97.501 through §97.535 |
| **Note:** §97.506(c) NOx emissions requirements. For TR NOx Ozone Season emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Ozone Season source and each TR NOx Ozone Season unit at the source shall hold, in the source's compliance account, TR NOx Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Ozone Season units at the source. |
| Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NOx Ozone Season allowance transfer must be submitted for recordation in a TR NOx Ozone Season source's compliance account in order to be available for use in complying with the source's TR NOx Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524. |

D. Control of Carbon Monoxide

PSD Approval

**CPCN Order No. 68851 Case No. 8063 conditions 17 and 18** which limits carbon monoxide emissions to 90 pounds per hour per combustion turbine when firing natural gas and 91 pounds per hour when firing distillate fuel oil. Total annual emissions of carbon monoxide from the two turbines are limited to 263 tons per consecutive 12-month period.

E. Control of VOC

**CPCN Order No. 68851 Case No. 8063 conditions 17 and 18** which limits VOC emissions to 2 pounds per hour per combustion turbine when firing natural gas and 4 pounds per hour when firing distillate fuel oil. Total
annual emissions of VOC from the two turbines are limited to 9.2 tons per consecutive 12-month period.

F. Control of Particulate Matter
PSD Approval
CPCN Order No. 68851 Case No. 8063 conditions 17 and 18 which limits PM\(_{10}\) and total particulates emissions 21 pounds per hour per combustion turbine when firing natural gas and 27 pounds per hour when firing distillate fuel oil. Total annual emissions of particulates from the two turbines are limited to 60 tons per consecutive 12-month period.

G. Operating Limitation on Fuel Use
The combustion turbines shall generate electricity using natural gas only. This requirement shall not apply during those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract during maintenance and repair. At such times, the unit shall use No. 2 oil only. Natural gas service curtailments or interruptions shall be verified by a letter each year from the unit’s natural gas supplier identifying the dates on which gas service was restricted.

[Reference: CPCN Order #68851 Case No. 8063 and see note under Table IV-3.4 paragraph G – letter further defining gas curtailment]

3.2 Testing Requirements:

A. Control of Visible Emissions:
See Monitoring Requirements.

B. Control of Sulfur Oxides:
See Monitoring Requirements.

C. Control of Nitrogen Oxides:
1. NO\(_X\) RACT
If the gas turbine operates more than 500 hours during a calendar year, the Permittee shall perform a combustion analysis and optimize combustion at least once annually. [Reference: COMAR 26.11.09.08G(1)(b)]

2. PSD Limitation
See Monitoring Requirements

Note: The Permittee is required to perform NO\(_X\) testing on the two turbines to satisfy the requirements of the Acid Rain Program. The Permittee
Table IV – 3

<table>
<thead>
<tr>
<th>Description</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Currently performs testing in accordance with Appendix E of 40 CFR Part 75</td>
<td>The results of this testing will be used to support the demonstration of compliance with NO\textsubscript{X} standards and limits of the PSD Approval and NSPS Subpart GG. See quality assurance requirements for the continuous monitoring for NO\textsubscript{X} for 40 CFR Part 75- Acid Rain Program. [Reference: Acid Rain Permit, CAIR Permit, 40 CFR 75 Appendix E]</td>
</tr>
<tr>
<td>3. NSPS Subpart GG</td>
<td>See Monitoring Requirements.</td>
</tr>
<tr>
<td>4. Acid Rain Permit</td>
<td>See QC/QA requirements in Acid Rain Permit.</td>
</tr>
<tr>
<td>5. Cross-State Air Pollution Rule</td>
<td>See Monitoring Requirements.</td>
</tr>
<tr>
<td>D. Control of Carbon Monoxide</td>
<td>See Monitoring Requirements.</td>
</tr>
<tr>
<td>E. Control of VOC</td>
<td>See Monitoring Requirements.</td>
</tr>
<tr>
<td>F. Control of Particulate Matter</td>
<td>See Monitoring Requirements.</td>
</tr>
<tr>
<td>G. Operating Limitation on Fuel Use</td>
<td>See Monitoring Requirements.</td>
</tr>
</tbody>
</table>

3.3 Monitoring Requirements:

A. Control of Visible Emissions
The Permittee shall verify that there are no visible emissions when burning No.2 fuel oil. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period at least once every 168 hours of operation on oil or at a minimum once per calendar year. The Permittee shall perform the following, if emissions are visible to human observer:
(a) inspect combustion control system and combustion turbine operations,
(b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and
(c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine.
(d) after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform a Method 9 observation once daily when combustion turbine is operating for 18 minutes until corrective action have eliminated visible emissions. The requirement for the observation is waived if no fuel oil is burned in the combustion turbines during a calendar year.

[Reference: COMAR 26.11.03.06C]

B. Control of Sulfur Oxides:

1. PSD Approval
The Permittee shall comply with the monitoring requirements of New Source Performance Standards (NSPS), Subpart GG, 40, CFR 60.334.

[Reference: CPCN Order No. 68851 Case No. 8063 condition 16]

2. NSPS Subpart GG:

40 CFR 60.334:

(h)(1) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference- see §60.17), which measure the major sulfur compounds may be used”;

(h)(3) “Notwithstanding the provisions of paragraph (h) (1) of this section, the owner or operator may elect not to monitor the sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to part 75 of this chapter is required.”

(h)(4) “For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a
custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule”.

(i) “The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:"

(1) “Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit’s storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day”.

3. Acid Rain Permit
The Permittee shall continuously monitor sulfur dioxide emissions that meet the requirements of 40 CFR Part 75, subpart B §75.10A(1). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with the Acid Rain Program. [Reference: Acid Rain Permit].

4. Cross-State Air Pollution Rule
The Permittee shall comply with the monitoring requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633.

C. Control of Nitrogen Oxides:
1. NOx RACT
   See Record Keeping Requirements.

2. PSD Limitation
   Same as for NSPS Subpart GG requirements

3. NSPS Subpart GG
   For oil firing
   40 CFR 60.334:
   (a) “Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine”.

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<th>Table IV – 3</th>
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<tr>
<td>custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule”.</td>
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(i) “The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:"

(1) “Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit’s storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day”.

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The Permittee shall continuously monitor sulfur dioxide emissions that meet the requirements of 40 CFR Part 75, subpart B §75.10A(1). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with the Acid Rain Program. [Reference: Acid Rain Permit].

4. Cross-State Air Pollution Rule
The Permittee shall comply with the monitoring requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633.

C. Control of Nitrogen Oxides:
1. NOx RACT
   See Record Keeping Requirements.

2. PSD Limitation
   Same as for NSPS Subpart GG requirements

3. NSPS Subpart GG
   For oil firing
   40 CFR 60.334:
   (a) “Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine”.

Page 112 of 140
Table IV – 3

For natural gas firing with dry low NO\textsubscript{X} burners
40 CFR 60.334:
(c) If the owner or operator has previously received State approval of a procedure for monitoring compliance with the applicable NO\textsubscript{X} emission limit under Sec. 332 that approved method may continue to be used. The Permittee shall monitor NO\textsubscript{X} emission rate using methodology in appendix E to 40 CFR 75. The parametric monitoring described in section 2.3 of appendix E shall be followed. The Permittee shall keep on-site a quality-assurance plan, as described in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR 75.

4. Acid Rain Permit
See the requirements for the continuous monitoring for NO\textsubscript{X} for 40 CFR Part 75 - Acid Rain Program. [Reference: Acid Rain Permit, 40 CFR 75 subpart B and Appendix E]

5. Cross-State Air Pollution Rule
The Permittee shall comply with the monitoring requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the NO\textsubscript{X} Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NO\textsubscript{X} Ozone Season Trading Program.

D. Control of Carbon Monoxide
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. [Reference: COMAR 26.11.03.06C]

E. Control of VOC
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. [Reference: COMAR 26.11.03.06C]

F. Control of Particulate Matter
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they operate as designed. [Reference: COMAR 26.11.03.06C]

G. Operating Limitation on Fuel Use
See Record Keeping Requirements.

3.4 Record Keeping Requirements:
Note: All records must be maintained for a period of at least 5 years. [Reference: COMAR 26.11.03.06C(5)(g)]
### Table IV – 3

<table>
<thead>
<tr>
<th>A. Control of Visible Emissions</th>
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<tbody>
<tr>
<td>The Permittee shall maintain a copy of the visible emissions observations on site for at least five years and make available to the Department upon request. [Reference: COMAR 26.11.03.06C]</td>
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</table>

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<th>B. Control of Sulfur Oxides:</th>
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<tr>
<td>1. PSD Approval</td>
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<tr>
<td>See NSPS monitoring requirements.</td>
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<tr>
<td>2. NSPS requirement</td>
</tr>
<tr>
<td>The Permittee shall comply with the record keeping monitoring requirements of New Source Performance Standards (NSPS), Subpart A, 40 CFR 60.7(f). [Reference: CPCN Order No. 68851 Case No. 8063 condition 16]</td>
</tr>
</tbody>
</table>

**40 CFR 60.7(f):**

“(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection.”

<table>
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<tr>
<th>3. Acid Rain Permit</th>
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<tbody>
<tr>
<td>See the recordkeeping requirements for 40 CFR Part 75- Acid Rain Program. [Reference: Acid Rain Permit, 40 CFR 75 subpart F]</td>
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<tr>
<th>4. Cross-State Air Pollution Rule</th>
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<td>The Permittee shall comply with the recordkeeping requirements found in §97.606, §97.630, and §97.634.</td>
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<th>C. Control of Nitrogen Oxides</th>
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<tbody>
<tr>
<td>1. NOx RACT</td>
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<td>The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. The Permittee shall maintain records if the calculations of the capacity factors. [Reference: COMAR 26.11.09.08G(1)(c) &amp; COMAR 26.11.03.06C]</td>
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Table IV – 3

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</table>
| 2. PSD Limitation | The Permittee shall maintain records of test results, analyses of nitrogen content of the fuel and the water to fuel ratio.  
[Reference: CPCN Order No. 68851 Case No. 8063] |
| 3. NSPS Subpart GG | 40 CFR 60.7(f):  
“(f)Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection.” |
| 4. Acid Rain Permit | See the recordkeeping requirements for 40 CFR Part 75- Acid Rain Program.  
[Reference: Acid Rain Permit, 40 CFR 75 subpart F] |
| 5. Cross-State Air Pollution Rule | The Permittee shall comply with the recordkeeping requirements found in §97.406, §97.430, and §97.434 for the NO\textsubscript{X} Annual Trading Program; and §97.506, §97.530, and §97.534 for the NO\textsubscript{X} Ozone Season Trading Program. |
| D. Control of Carbon Monoxide | The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance.  
[Reference: COMAR 26.11.03.06C]. |
| E. Control of VOC | The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance.  
[Reference: COMAR 26.11.03.06C]. |
| F. Control of Particulate Matter | The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance.  
[Reference: COMAR 26.11.03.06C]. |
| G. Operating Limitation on Fuel Use | The Permittee shall maintain records to support the basis for burning fuel |
oil, either those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract during maintenance and repair.  

[Reference: CPCN Order #68851 Case No. 8063 & COMAR 26.11.03.06C]

Note: The Department, in a February 2, 2006 letter to GenOn, concurred with GenOn’s proposal to clarify natural gas curtailments as follows: Gas pipeline is out of service for maintenance or repair. Documentation of these events will be obtained through postings on the gas supplier’s website; Gas supply is interrupted under the delivery contract. Documentation of these events will be obtained through postings on the gas supplier’s website; One or more of the CT Units is called for by PJM to start or extend operation during periods of time when the pipeline operator is not open for business, typically between 6:00 PM and 10:00 AM daily. GenOn will document PJM dispatch notices during these occasions and will purchase gas upon opening of the commercial gas trading market- typically, 10:00 AM, provided the price of delivered gas is not 15% or more of the price of delivered oil.

The 15% cost differential between natural gas and #2 fuel oil will be determined on the following basis: Daily publications from the Platts service will be utilized as representative industry benchmarks of natural gas and #2 oil pricing. GenOn will document delivered gas-to-oil cost differential using these benchmarks. The delivered cost of #2 oil for GenOn facilities is calculated by taking the Platts Oilgram New York Harbor Barge price and adding $0.0564/gallon in delivery charges. The delivered cost of natural gas for GenOn facilities is calculated by taking the Platts Gas Daily Transco Zone 6 Non-New York price and adding $0.10/MMBtu for delivery and $0.22/MMBtu in Park and Loan fees. The delivered prices for #2 oil and natural gas are calculated on a daily basis to determine if the 15% cost differential is met for the current day unit dispatch.

CTs allowed to run on oil for test purposes after repairs or maintenance of the fuel oil system and its appurtenances for operability assurance.

3.5 Reporting Requirements:

A. Control of Visible Emissions:
The Permittee shall report incidents of visible emissions in accordance with permit condition 4, Section III, Plant Wide Conditions, “Report of Excess Emissions and Deviations”.  [Reference: COMAR 26.11.03.06C]

B. Control of Sulfur Oxides:
1. PSD Approval:
The Permittee shall submit quarterly reports to the Department and the Public Service Commission that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, average and maximum sulfur contents of the fuel oil, average and maximum nitrogen contents of the fuel oil, average sulfur content of the natural gas, total calculated \( \text{SO}_x \) (expresses as \( \text{SO}_2 \)) emissions and total calculated \( \text{NO}_x \) emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department. [Reference: CPCN Order No. 68851 Case No. 8063 condition 28] Note: The Part 70 general record keeping requirements requires records to be maintained for 5 years.

2. NSPS Subpart GG
40 CFR 60.334(j) - For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:
(1) (Nitrogen oxides requirement)
(2) Sulfur dioxide.
   (i) “For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit’s storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.”
   (iii) “A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample”.

§60.7(c) - “Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to
accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

1. The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

2. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

3. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

4. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.”

3. Acid Rain Permit
See the reporting requirements for 40 CFR Part 75- Acid Rain Program.
[Reference: Acid Rain Permit, 40 CFR 75 subpart G]

4. Cross-State Air Pollution Rule
The Permittee shall comply with the reporting requirements found in §97.606, §97.630, §97.633 and §97.634.

C. Control of Nitrogen Oxides
1. NO\textsubscript{X} RACT
The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with the support documentation in the Annual Emission Certification Report. [Reference: COMAR 26.11.09.08G(1)(a) COMAR 26.11.03.06C].

2. PSD Limitation
In addition to NSPS requirements, the Permittee shall also report quarterly, to the Department, any one-hour period during which the average water-to-fuel ratio fell below the water-to-fuel ration used to demonstrate compliance with the NO\textsubscript{X} emission concentration limit. [Reference: CPCN Order 68851 Case 8063 condition 16]

The Permittee shall submit quarterly reports to the Department that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, average and maximum
nitrogen contents of the fuel oil, and total calculated NO\textsubscript{X} emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department. [Reference: CPCN Order No. 68851 Case No. 8063 condition 28]

3. NSPS Subpart GG
40 CFR 60.334:
(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio,
average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owner or operators that elect to monitor combustion parameters or parameters that document proper operation of the NO\textsubscript{X} emissions controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any
of the required parametric data are either not recorded or are invalid.

§60.7(c) - “Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

1. The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

2. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

3. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

4. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.”

4. Acid Rain Permit

See the reporting requirements for 40 CFR Part 75- Acid Rain Program.
[Reference: Acid Rain Permit, 40 CFR 75 subpart G]

5. Cross-State Air Pollution Rule.
The Permittee shall comply with the reporting requirements found in §97.406, §97.430, §97.433 and §97.434 for the NOx Annual Trading Program; and §97.506, §97.530, §97.533, and §97.534 for the NOx Ozone Season Trading Program.

D. Control of Carbon Monoxide
The Permittee shall submit records of maintenance to the Department upon request. [Reference: COMAR 26.11.03.06C]

E. Control of VOC
The Permittee shall submit records of maintenance to the Department upon
F. Control of Particulate Matter
The Permittee shall submit records of maintenance to the Department upon request. [Reference: COMAR 26.11.03.06C]

G. Operating Limitation on Fuel Use
Natural gas service curtailments shall be verified by a letter each year from the unit’s natural gas supplier identifying the dates on which gas service was restricted. [Reference: CPCN Order #68851 Case No. 8063]

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”

Table IV – 4

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<thead>
<tr>
<th>4.0</th>
<th>Emissions Unit Number(s)</th>
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<td>Ash and coal handling operations.</td>
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<th>4.1</th>
<th>Applicable Standards/Limits:</th>
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Control of Particulate Matter

COMAR 26.11.06.03C - Particulate Matter from Unconfined Sources.
“(1) A person may not cause or permit emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, when appropriate as determined by the Department, the installation and use of hoods, fans, and dust collectors to enclose, capture, and vent emissions. In making this determination, the Department shall consider technological feasibility, practicality, economic impact, and the environmental consequences of the decision.”

COMAR 26.11.06.03D - Particulate Matter from Materials Handling and Construction. “A person may not cause or permit any material to be handled, transported, or stored, or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer:
(1) Use of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land.
(2) Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can create airborne dusts. (3) Installation and use of hoods, fans, and dust collectors to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting of buildings or other similar operations. (4) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution. Alternate means may be employed to achieve the same results as would covering the vehicles. (5) The paving of roadways and their maintenance in clean condition. (6) The prompt removal from paved streets of earth or other material which has been transported there by trucks or earth moving equipment or erosion by water.”

### 4.2 Testing Requirements:

See Monitoring Requirements.

### 4.3 Monitoring Requirements:

The Permittee shall prepare and maintain a best management practices (BMPs) plan that contains an explanation of the reasonable precautions that will be used to prevent particulate matter from becoming airborne.

The Permittee shall perform a walk through inspection of the facility to look for fugitive emissions, to verify that reasonable precautions are being implemented and to determine whether the reasonable precautions need to be revised. The inspection shall be conducted at a minimum of once per month at times when the effectiveness of the reasonable precautions can be assessed. [Reference: COMAR 26.11.03.06C].

### 4.4 Record Keeping Requirements:

The Permittee shall keep the results of the monthly inspections for a period of five (5) years. The Permittee shall maintain the best management practices (BMPs) plan at the facility. [Reference: COMAR 26.11.03.06C].

### 4.5 Reporting Requirements:

See Record Keeping Requirements.

“A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above.”
SECTION V INSIGNIFICANT ACTIVITIES

This section provides a list of insignificant emissions units that were reported in the Title V permit application. The applicable Clean Air Act requirements, if any, are listed below the insignificant activity.

(1) No. 6 Stationary internal combustion engines with an output less than 500 brake horsepower (373 kilowatts) and which are not used to generate electricity for sale or for peak or load shaving;

These affected units are subject to the following requirements:

(A) COMAR 26.11.09.05E(2), Emissions During Idle Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity.

(B) COMAR 26.11.09.05E(3), Emissions During Operating Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

(C) Exceptions:

(i) COMAR 26.11.09.05E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

(ii) COMAR 26.11.09.05E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:

(a) Engines that are idled continuously when not in service: 30 minutes

(b) all other engines: 15 minutes.

(iii) COMAR 26.11.09.05E(2) & (3) do not apply while maintenance, repair or testing is being performed by qualified mechanics.

(D) COMAR 26.11.09.07A(2)(b), which establishes that the Permittee may not burn, sell, or make available for sale any distillate fuel with a sulfur content by weight in excess of 0.3 percent.

(E) COMAR 26.11.36.03A(1), which establishes that the Permittee may not operate an emergency generator except for emergencies, testing and maintenance purposes.
(F) COMAR 26.11.36.03A(5), which establishes that the Permittee may not operate an emergency generator for testing and engine maintenance purposes between 12:01 a.m. and 2:00 p.m. on any day on which the Department forecasts that the air quality will be a code orange, code red, or code purple unless the engine fails a test and engine maintenance and a re-test are necessary.

(2)  Space heaters utilizing direct heat transfer and used solely for comfort heat;

(3)  No. 50 Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

These affected units are subject to COMAR 26.11.19.09D, which requires that the Permittee control emissions of volatile organic compounds (VOC) from cold degreasing operations by meeting the following requirements:

(a) COMAR 26.11.19.09D(2)(b), which establishes that the Permittee shall not use any VOC degreasing material that exceeds a vapor pressure of 1 mm Hg at 20 ° C;

(b) COMAR 26.11.19.09D(3)(a—d), which requires that the Permittee implement good operating practices designed to minimize spills and evaporation of VOC degreasing material. These practices, which shall be established in writing and displayed such that they are clearly visible to operators, shall include covers (including water covers), lids, or other methods of minimizing evaporative losses, and reducing the time and frequency during which parts are cleaned;

(c) COMAR 26.11.19.09D(4), which prohibits the use of any halogenated VOC for cold degreasing.

The Permittee shall maintain on site for at least five (5) years, and shall make available to the Department upon request, the following records of operating data:
(a) Monthly records of the total VOC degreasing materials used; and
(b) Written descriptions of good operating practices designed to minimize spills and evaporation of VOC degreasing materials.

(4) ✔ Equipment for drilling, carving, cutting, routing, turning, sawing, planing, spindle sanding, or disc sanding of wood or wood products;

(5) ✔ Brazing, soldering, or welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals and not directly related to plant maintenance, upkeep and repair or maintenance shop activities;

(6) Containers, reservoirs, or tanks used exclusively for:
   (a) ✔ Storage of butane, propane, or liquefied petroleum, or natural gas;
   (b) No.  75 Storage of lubricating oils;
   (c) No.  6 Storage of Numbers 1, 2, 4, 5, and 6 fuel oil and aviation jet engine fuel;
   (d) No.  1 Storage of motor vehicle gasoline and having individual tank capacities of 2,000 gallons (7.6 cubic meters) or less;
   (e) No.  50 The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(7) ✔ First aid and emergency medical care provided at the facility, including related activities such as sterilization and medicine preparation used in support of a manufacturing or production process;

(8) ✔ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;
(9) ✔ Potable water treatment equipment, not including air stripping equipment;

(10) ✔ Comfort air conditioning subject to requirements of Title VI of the Clean Air Act;

(11) ✔ Natural draft hoods or natural draft ventilators that exhaust air pollutants into the ambient air from manufacturing/industrial or commercial processes;

(12) ✔ Laboratory fume hoods and vents;
SECTION VI  STATE-ONLY ENFORCEABLE CONDITIONS

The Permittee is subject to the following State-only enforceable requirements:

1. Applicable Regulations:

COMAR 26.11.06.08 – Nuisance. “An installation or premises may not be operated or maintained in such a manner that a nuisance or air pollution is created. Nothing in this regulation relating to the control of emissions may in any manner be consumed as authorizing or permitting the creation of, or maintenance of, nuisance or air pollution.”

COMAR 26.11.06.09 - Odors. “A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created.”

<table>
<thead>
<tr>
<th>Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, &amp; 3-0003)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Applicable Standards/Limits:</th>
</tr>
</thead>
<tbody>
<tr>
<td>COMAR 26.11.09.05. – Visible Emissions.</td>
</tr>
<tr>
<td>“A. Fuel Burning Equipment.</td>
</tr>
<tr>
<td>(4) Fuel Burning Equipment Required to Operate a COM. The owner or operator of fuel burning equipment that is subject to the requirement to install and operate a COM shall demonstrate compliance with the applicable visible emissions limitation specified in §A(1) and (2) of this regulation as follows:</td>
</tr>
<tr>
<td>(a) For units with a capacity factor greater than 25 percent, until December 31, 2009, compliance is achieved if visible emissions do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4 percent of the unit's operating time in any calendar quarter, during which time visible emissions:</td>
</tr>
<tr>
<td>(i) Do not exceed 40.0 percent opacity, except for 5.0 hours or 0.5 percent of the unit's operating time, whichever is greater;</td>
</tr>
<tr>
<td>(ii) Do not exceed 70.0 percent opacity for more than four (4) 6-minute periods, except that coal-fired units equipped with electrostatic precipitators may exceed 70.0 percent opacity for no more than 2.2 hours; and</td>
</tr>
</tbody>
</table>
(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two (2) six-minute periods;

(b) For units with a capacity factor greater than 25 percent, beginning January 1, 2010, compliance is achieved if visible emissions do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 2 percent of the unit's operating time in any calendar quarter, during which time visible emissions:

(i) Do not exceed 40.0 percent opacity, except for 5.0 hours or 0.5 percent of the unit's operating time, whichever is greater;

(ii) Do not exceed 70.0 percent opacity for more than four (4) six-minute periods, except that coal-fired units equipped with electrostatic precipitators may exceed 70.0 percent opacity for no more than 2.2 hours; and

(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two 6-minute periods;

(c) For units with a capacity factor equal to or less than 25 percent that operate more than 300 hours per quarter, beginning July 1, 2009, compliance with the applicable visible emissions limitation in §A(1) and (2) of this regulation is achieved if, during a calendar quarter, visible emissions do not exceed the applicable standard for more than 20.0 hours, during which time visible emissions:

(i) Do not exceed 40.0 percent opacity for more than 2.2 hours;

(ii) Do not exceed 70 percent for more than four 6-minute periods; and

(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two 6-minute periods; and

(d) For units with a capacity factor equal to or less than 25 percent that operate 300 hours or less per quarter, beginning July 1, 2009, compliance with the applicable visible emissions limitation in §A(1) and (2) of this regulation is achieved if, during a calendar quarter, visible emissions do not exceed the applicable standard for more than 12.0 hours, during which time visible emissions:

(i) Do not exceed 40.0 percent opacity for more than 2.2 hours;

(ii) Do not exceed 70.0 percent opacity for more than four 6-minute periods; and

(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4
hours and do not exceed 70.0 percent opacity for more than two 6-minute periods.

(5) Notwithstanding the requirements in §A(4) of this regulation, the Department may determine compliance and noncompliance with the visible emissions limitations specified in §A(1) and (2) of this regulation by performing EPA reference Method 9 observations.

(6) In no instance shall excess emissions exempted under this regulation cause or contribute to a violation of any ambient air quality standard in 40 CFR Part 50, as amended, or any applicable requirements of 40 CFR Part 60, 61, or 63, as amended. “

“B. Determining Violations.

(1) For each unit required to operate a COM pursuant to COMAR 26.11.01.10A(1)(a) and (b), each day during a calendar quarter when the opacity of emissions from that unit during the calendar quarter or calendar day, as applicable, exceeds the emission limitations in §A(4)(a), (b), (c) and (d) of this regulation shall constitute a separate day of violation.

(2) A violation of §A(4)(a)(i), (ii), or (iii), §A(4)(b)(i), (ii) or (iii), §A(4)(c)(i), (ii) or (iii), or §A(4)(d)(i), (ii) or (iii), of this regulation, as applicable, that occur on the same day shall constitute separate violations.

(3) A daily violation that occurs during the same calendar quarter as a quarterly violation is a separate violation. “

“C. Fuel Burning Equipment Subject to Federal COM Requirements. Except for owners or operators of fuel burning equipment subject to any federal requirement that mandates operation of a COM and as provided in §D of this regulation, the owner or operator of fuel burning equipment required to install and operate a COM may discontinue the operation of the COM on fuel burning equipment that is served by a flue gas desulfurization device:

(1) When emissions from the equipment do not bypass the flue gas desulfurization device serving the equipment;

(2) When the flue gas desulfurization device serving the equipment is in operation;

(3) If the owner or operator has demonstrated to the Department's satisfaction, in accordance with 40 CFR §75.14, as amended, and all other applicable State and federal requirements, that water vapor is present in the flue gas from the equipment and would impede the accuracy of opacity measurements; and

(4) If the owner or operator has fully implemented an alternative plan, approved by the Department, for monitoring opacity levels and particulate matter emissions from the stack that includes:

(a) A schedule for monthly observations of visible emissions from the stack by a person trained to perform Method 9 observations; and

(b) Installation and operation of a particulate matter CEM that complies with all applicable State and federal requirements for particulate matter CEMs. “
“D. If, for units equipped with a flue gas desulfurization device, emissions bypass the device and are discharged through a bypass stack, the bypass stack shall be equipped with a COM approved by the Department.”

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### March 2008 Opacity Consent Decree

**Emissions Unit Number(s):** D-1, D-2, & D-3: Boilers Cont’d

**March 2008 Opacity Consent Decree**

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. *(3-0001, 3-0002, & 3-0003)*

### Applicable Requirements:

**Control of Visible Emissions**

*Completed:* Consent Decree Section V. Evaluation of Opacity Exceedances, paragraphs 7, 8, 9, 10.

**Compliance Assurance Monitoring**

*Completed:* Consent Decree Section VII. Implementation of Interim and Final CAM Plans, paragraphs 19, 20, 21, 22, 23, 24, 25.

**Particulate Matter Stack Testing**

*Completed:* Consent Decree Section VIII. Particulate Matter Stack Testing, paragraphs 26, 27, 28. *See letter dated October 6, 2011 – Petition to stop 170-day stack testing.*

**Improvements to the Dickerson Baghouse**

*Completed.* Consent Decree Section IX: Improvements to the Dickerson Baghouse, paragraphs 29, 30

*Completed.* Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 31, 32.

17. GenOn shall use reasonable efforts to keep each PM CEMS operating and producing data whenever a Unit served by the PM CEMS is operating. *[Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 33.]*
March 2008 Opacity Consent Decree

18. Completed. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 34.]

19. GenOn shall provide the Department with written notice of the date on which initial operation of each PM CEMS is commenced. No later than 90 days following initial operation of a PM CEMS, GenOn shall submit to the Department for review and approval a proposed Quality/Assurance/Quality Control (“QA/QC”) protocol for that PM CEMS, including a maintenance schedule, which shall be followed in calibrating and operating the PM CEMS. The protocol shall be developed in accordance with EPA Procedures 2 of Appendix F or 40 CFR Part 60 (“Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems Used at Stationary Sources”). GenOn shall operate each PM CEMS in accordance with the approved protocol. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 35]

20. GenOn shall submit quarterly PM CEMS reports to the Department that comply with COMAR 26.11.01.11E(2)(c). All data shall be reported in 24-hour rolling averages. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 36]


22. PM CEMs data shall not be used to demonstrate compliance with the applicable particulate matter emission limitation until the 181st day following installation of the PM CEMS on that Unit, except with regard to Morgantown Units 1 and 2, as to which the provisions of Paragraph 41 shall govern the 90-day period subsequent to the 180 day following the installation of the PM CEMS. Commencing on the 181st day following installation of the PM CEMS, CEMs data may be used to demonstrate compliance with applicable particulate matter emission limitations unless GenOn asserts that the continued operation of the PM CEMS is impracticable. In such event, PM CEMS shall not be used to demonstrate compliance with the applicable particulate matter emission limitation unless and until the Department determines that the continued operation of the PM CEMS is not impracticable. Unless, otherwise required by State or federal law or regulation, in demonstrating compliance, particulate emissions during periods of startup and shutdown shall not be included. Periods of startup shall end at such time as the Unit reaches minimum load levels. For Dickerson Units 1, 2 and 3, minimum load is reached when the Unit generates 75 gross megawatts. The Department may approve a longer startup period for a Unit if necessary to ensure that the PM CEMS serving that Unit is accurately recording particulate emissions. Periods of shutdown shall only commence when the Unit ceases
burning any amount of coal. GenOn shall maintain a record of the date and time that: (a) startup commenced; (b) minimum load was reached; and (c) combustion of coal ceased. GenOn shall make such records available to the Department upon request. At all times when PM CEMs are used to demonstrate compliance, each PM CEMs shall, at a minimum, obtain valid PM CEMs hourly averages for 75% of all operating hours on a 30-day rolling average. Commencing on January 1, 2012, GenOn shall use all reasonable efforts to obtain valid PM CEMs hourly averages for a minimum of 90% of all operating hours on a 30-day rolling average. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 38]

23. Unless otherwise required by State or federal law or regulation, upon initial operation of an FGD pollution control device on a Unit subject to this Consent Decree, GenOn may discontinue use of opacity CEMs to monitor the opacity emissions from the stack serving such Unit, provided that: (a) emissions from such Unit do not bypass the FGD serving that Unit and FGD technology serving that Unit is in operation; (b) GenOn has fully implemented an alternative plan for monitoring opacity levels and particulate matter emissions from the stack serving such Unit that has been approved by the Department; and (c) GenOn has demonstrated to the satisfaction of the Department and the United States Environmental Protection Agency, in accordance with 40 CFR §75.14 and applicable EPA regulations, policy and guidelines, that condensed water is present in the flue gas stream from such Unit and would impede the accuracy of opacity measurements. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 39]

Mist Eliminators
24. GenOn shall install and maintain a mist eliminator in each FGD/SO₂ absorber for Dickerson Units 1, 2 and 3, as specified in each of GenOn’s separate applications for a CPCN to install FGD technology at the Plants. [Reference: Consent Decree Section XIII. Mist Eliminators, paragraph 44] Completed.

Reporting Requirements
25. Beginning with the quarter that commences on January 1, 2008, GenOn shall submit to the Department quarterly reports describing the status of GenOn’s compliance with the terms and conditions of the Consent Decree. Each quarterly report shall be due no later than 30 days following the end of the quarter, unless such date falls on a weekend or holiday, in which case the report shall be due on the next business day. The first quarterly report shall be due on April 30, 2008. [Reference: Consent Decree Section XIV. Reporting, paragraph 45]

26. Past. Completed. [Reference: Consent Decree Section XIV. Reporting, paragraph 46]
Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d

Alternate Operating Scenario for Emission Units D-1, D-2 and D-3
The Permittee shall burn used oil and boiler chemical cleaning waste materials in the utility boilers.

COMAR 26.11.09.10 - Requirements to Burn Used Oil and Waste Combustible Fluid as Fuel.

Applicable Regulations:
A. “General Requirements.
(1) A person who proposes to burn used oil or waste combustible fluid in an installation shall submit the following information to the Department:
(a) A description of, and the location of, each fuel-burning equipment or other installation in which the used oil or WCF is to be burned and the rated heat input capacity of each;
(b) The type and amount of fuel currently being used in each installation and the gallons of used oil or WCF expected to be burned annually;
(c) The maximum percentage of used oil or WCF to be burned as fuel in each installation; and
(d) An analysis by an independent laboratory of a representative sample of the used oil or WCF, which shall include the concentration of each of the materials listed in §B of this regulation, the PCB concentration, and the flash point.

(2) A person may burn on-specification used oil in any installation upon submitting the information required in §A(1) of this regulation.
(3) A person who is burning used oil or WCF under a current approval issued by the Department may continue to burn the approved material if:
(a) The person registers the equipment that is burning the used oil or WCF by submitting the information required in §A(1) of this regulation; and
(b) The used oil or WCF is being burned in an authorized installation.

(4) A person who proposes to burn off-specification used oil or WCF in an installation other than a space heater, as provided in 40 CFR §279.23, is subject to the permit or registration requirements in COMAR 26.11.02.
(5) A person who receives a permit or registration to burn used oil or WCF shall burn only the materials authorized in the permit or registration.
(6) A person may burn off-specification used oil and waste combustible fluid only in those installations listed at 40 CFR §279.12(c).”
Specifications for Used Oil.
(1) Except as provided in §B(2) of this regulation, used oil specifications are as follows:

<table>
<thead>
<tr>
<th>Material</th>
<th>Allowable Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lead</td>
<td>100 ppm</td>
</tr>
<tr>
<td>Total halogens</td>
<td>4,000 ppm</td>
</tr>
<tr>
<td>Arsenic</td>
<td>5 ppm</td>
</tr>
<tr>
<td>Cadmium</td>
<td>2 ppm</td>
</tr>
<tr>
<td>Chromium</td>
<td>10 ppm</td>
</tr>
<tr>
<td>Flash point</td>
<td>100° F minimum</td>
</tr>
</tbody>
</table>

(2) For used oil that does not satisfy the rebuttable presumption for halogens at 40 CFR 279.10(b)(1)(ii) and 279.63, the maximum allowable level for halogens may not exceed 1,000 ppm.”

Record keeping
The Permittee shall maintain a record of the quantity of used oil that is burned and analyses by an independent laboratory of representative samples of the used oil.

Healthy Air Act Requirements
These regulations became effective under an Emergency Action on January 18, 2007 and were adopted as permanent regulations on June 17, 2007. They implement the requirements of the Healthy Air Act (Ch. 23, Acts of 2006), which was signed into law on April 6, 2006 and which established emission limitations and related requirements for NOX, SO2 and mercury. Regulations .01-.03, .03E, .05 and .06, related to the reductions of NOX and SO2 emissions, were submitted to EPA as a revision to Maryland’s State Implementation Plan (SIP) on June 12, 2007. The requirements for NOX and SO2 emissions, all except for one were approved by EPA, as a SIP revision on September 4, 2008 with an effective date of October 6, 2008. The requirements for mercury emissions are not part of the Maryland’s SIP and are therefore, part of the State-Only Section.

Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d
Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003)
**Applicable Regulations:**

<table>
<thead>
<tr>
<th>COMAR 26.11.27 - Emission Limitations for Power Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>COMAR 26.11.27.03 – General Requirements</strong></td>
</tr>
<tr>
<td>A. An electric generating unit subject to this chapter shall comply with the emission limitations for NO(\text{X}), SO(\text{2}), and mercury as provided in this regulation.</td>
</tr>
</tbody>
</table>

**B. NO\(\text{X}\) Emission Limitations.**

**Healthy Air Act State-Only enforceable NO\(\text{X}\) requirement**

**COMAR 26.11.27.03B(7)(iii)** – “Not later than December 31 of the year in which the emission limitation is exceeded, the owner or operator of the affected generating unit or units transfers to the Maryland Environmental Surrender Account, ozone season NO\(\text{X}\) allowances equivalent in number to the tons of NO\(\text{X}\) emitted in excess of the emission limitation in §B(4) or (6), as applicable”.

**COMAR 26.11.27.03D. Mercury Emission Limitations.**

1. For the 12 months beginning January 1, 2010 and ending with the 12 months beginning December 1, 2012 to December 1, 2013, each affected facility shall meet 12-month rolling average removal efficiency for mercury of at least 80 percent.
2. For the 12 months beginning January 1, 2013 and thereafter, each affected facility shall meet 12-month rolling average removal efficiency for mercury of at least 90 percent.
3. The mercury removal efficiency required in §D(1) and (2) of this regulation shall be determined in accordance with Regulation .04 of this chapter.

**COMAR 26.11.27.05 - Monitoring and Reporting Requirements.**

A. Compliance with the emission limitations in this chapter shall be demonstrated with a continuous emission monitoring system that is installed, operated, and certified in accordance with 40 CFR Part 75.

**COMAR 26.11.27.05 - Monitoring and Reporting Requirements.**

B. Beginning with calendar year 2007 and each year thereafter, the owner or operator of each electric generating unit subject to this chapter shall submit an annual report to the Department, the Department of Natural Resources, and the Public Service Commission. The report for each calendar year shall be submitted not later than March 1 of the following year.

C. Each report shall include:

1. Emissions performance results related to compliance with the emission requirements under this chapter;
2. Emissions of NO\(\text{X}\) and SO\(\text{2}\), and beginning with calendar year 2010, mercury, emitted during the previous calendar year from each affected unit;
3. A current compliance plan; and
(4) Any other information requested by the Department.

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**Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d**

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. *(3-0001, 3-0002, & 3-0003)*

**Applicable Regulations:**

**Management of Coal Combustion Byproducts**

COMAR 26.04.10.03 - General Restrictions and Specifically Prohibited Acts.

**(1) COMAR 26.04.10.03B(3) - Air Pollution**

“(a) A person may not engage in the disposal, storage, transportation, processing, handling, or use of coal combustion byproducts without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, when appropriate as determined by the Department, those precautions described in COMAR 26.11.06.03C and D.”

“(b) In addition to the requirements of paragraph (a), a person may not transport coal combustion byproducts without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, at a minimum the following:

(i) Vehicles transporting coal combustion byproducts shall be fully enclosed, or fully enclosed on all sides and covered with a firmly secured canvas or similar type covering, so as to prevent any coal combustion byproducts from blowing off, falling off, or spilling out of the vehicle or the coal combustion byproducts shall be handled and transported in sealed containers designed for transportation of powdery solids;

(ii) Before leaving a site where coal combustion byproducts are loaded or off-loaded, vehicles transporting coal combustion byproducts shall be rendered clean and free of excess material or debris that could blow off, fall off, or spill during transport;

(iii) Coal combustion byproducts being loaded into or off-loaded from a vehicle shall be sufficiently moistened or otherwise conditioned or contained to prevent particulate coal combustion byproducts from becoming airborne or causing fugitive air emissions; and...
(iv) Transporters of coal combustion byproducts shall maintain an inspection log that shall be maintained in each vehicle at all times during transport of coal combustion byproducts that shall certify compliance with the standards in this regulation .03B(3)(b).”

**Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d**

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBS and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. *(3-0001, 3-0002, & 3-0003)*

**COMAR 26.11.38 – Control of NO\textsubscript{X} Emissions from Coal-Fired Electric Generating Units.**

**Applicable Regulations:**

**COMAR 26.11.38.02 – Applicability**

“The provisions of this chapter apply to an affected electric generating unit as that term is defined in §.01B of this chapter.”

**COMAR 26.11.38.03 – NO\textsubscript{X} Emission Control Requirements**

**A. Daily NO\textsubscript{X} Reduction Requirements During the Ozone Season**

(1) Not later than 45 days after the effective date of this regulation, the owner or operator of an affected electric generating unit shall submit a plan to the Department and EPA for approval that demonstrated how each affected electric generating unit (“the unit”) will operate installed pollution control technology and combustion controls to meet the requirements of §A(2) of this regulation. The plan shall cover all modes of operation, including but not limited to normal operations, start-up, shut-down and low load operations. *Completed*

(2) Beginning on May 1, 2015, for each operating day during the ozone season, the owner or operator of an affected electric generating unit shall minimize NO\textsubscript{X} emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers’ specification, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 CFR §60.11(d)) for such equipment and the unit at all times the unit is in operation while burning any coal.
B. Ozone Season NO\textsubscript{X} Reduction Requirements.
   (1) Except as provided in §B(3) of this regulation, the owner or operator of an affected electric generating unit shall not exceed a NO\textsubscript{X} 30-day system-wide rolling average emission rate of 0.15 lbs/MMBtu during the ozone season.
   (2) The owner or operator of an affected electric generating unit subject to the provisions of this regulation shall continue to meet ozone season NO\textsubscript{X} reduction requirements in COMAR 26.11.27.

C. Annual NO\textsubscript{X} Reduction Requirements.
The owner of operator of an affected electric generating unit subject to the provisions of this regulation shall continue to meet the annual NO\textsubscript{X} reduction requirements in COMAR 26.11.27.

COMAR 26.11.38.04 – Compliance Demonstration Requirements
A. Procedures for demonstrating compliance with §.03(A) of this chapter.
   (1) An affected electric generating unit shall demonstrate, to the Department’s satisfaction, compliance with §.03(A)(2) of this chapter, using the information collected and maintained in accordance with §.03(A)(1) of this chapter and any additional demonstration available to and maintained by the affected electric generating unit.
   (2) An affected electric generating unit shall not be required to submit a unit-specific report consistent with §A(3) of this regulation when the unit emits at levels that are at or below the following rates:

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>24-Hour Block Average NO\textsubscript{X} Emissions in lbs/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson</td>
<td></td>
</tr>
<tr>
<td>Unit 1 only</td>
<td>0.24</td>
</tr>
<tr>
<td>Unit 2 only</td>
<td>0.24</td>
</tr>
<tr>
<td>Unit 3 only</td>
<td>0.24</td>
</tr>
<tr>
<td>Two or more Units combined</td>
<td>0.24</td>
</tr>
</tbody>
</table>

(3) The owner or operator of an affected electric generating unit subject to §.03(A)(2) of this chapter shall submit a unit-specific report for each day the unit exceeds its NO\textsubscript{X} emission rate of §A(2) of this regulation, which shall include the following information for the entire operating day:
   (a) Hours of operation for the unit;
   (b) Hourly averages of operating temperature of installed pollution control technology;
   (c) Hourly averages of heat input (MMBtu/hr);
   (d) Hourly averages of output (MWh);
   (e) Hourly averages of Ammonia or urea flow rates;
(f) Hourly averages of NO\textsubscript{X} emissions data (lbs/MMBtu and tons);  
(g) Malfunction data;  
(h) The technical and operational reason the rate was exceeded, such as:  
   (i) Operator error;  
   (ii) Technical events beyond the control of the operator (e.g. acts of God, malfunction); or  
   (iii) Dispatch requirements that mandate unplanned operation (e.g. start-ups and shut-down, idling and operation at low voltage or low load) 
(i) A written narrative describing any actions taken to reduce emission rates; and  
(j) Other information that the Department determines is necessary to evaluate the data or to ensure that compliance is achieved.

(4) An exceedance of the emissions rate if §A(2) of this regulation as a result of factors including but not limited to start-up and shut-down, days when the unit was directed by the electric grid operator to operate at low load or to operated pursuant to any emergency generation operations required by the electric grid operator, including necessary testing for emergency operations, or to have otherwise occurred during operations which are deemed consistent with the unit’s technological limitations, manufacturers’ specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions, shall not be considered a violation of §.03A(2) of this chapter provided that the provisions of the approved plan as required in §.03A(1) of this chapter are met.

B. Procedures for demonstrating compliance with NO\textsubscript{X} emission rates of this chapter.

(1) Compliance with the NO\textsubscript{X} emission rate limitations in §.03B(1), §.03D(2), and §.04A(2) of this chapter shall be demonstrated with a continuous emission monitoring system that is installed, operated, and certified in accordance with 40 CFR Part 75.

(2) For §.03B(1) of this chapter, in order to calculate the 30-day system-wide rolling average emissions rated, if twenty-nine system operating days are not available from the current ozone season, system operating days from the previous ozone season shall be used.

**COMAR 26.11.38.05 – Reporting Requirements**

A. Reporting Schedule

(1) Beginning 30 days after the first month of the ozone season following the effective date of this chapter, each affected electric generating unit subject to the requirements of this chapter shall submit a monthly report to the Department detailing the status of compliance with this chapter during the ozone season.
(2) Each subsequent monthly report shall be submitted to the Department not later than 30 days following the end of the calendar month during the ozone season.

B. Monthly Reports During Ozone Season.

Monthly reports during the ozone season shall include:
(1) Daily pass or fail of the NO\textsubscript{X} emission rates of §.04A(2) of this chapter.
(2) The reporting information as required under §.04A(3) of this chapter.
(3) The 30-day system-wide rolling average emissions rate for each affected electric generating unit to demonstrate compliance with §.03B(1) of this chapter.

2. Record Keeping and Reporting:

The Permittee shall submit to the Department, by April 1 of each year during the term of this permit, a written certification of the results of an analysis of emissions of toxic air pollutants from the Permittee’s facility during the previous calendar year. The analysis shall include either:

(a) a statement that previously submitted compliance demonstrations for emissions of toxic air pollutants remain valid; or

(b) a revised compliance demonstration, developed in accordance with requirements included under COMAR 26.11.15 & 16, that accounts for changes in operations, analytical methods, emissions determinations, or other factors that have invalidated previous demonstrations.
PHASE II ACID RAIN PERMIT

Plant Name: Dickerson
Affected Units: 1, 2, 3, GT2, and GT3
Owner: GenOn Mid-Atlantic, LLC
Effective Date From: November 1, 2015 To: October 31, 2020

Contents:

1. Statement of Basis

2. SO\textsubscript{2} and NO\textsubscript{x} requirements for each affected unit.

3. Comments, notes and justifications regarding permit decisions and changes made to permit application forms during the review process, and any additional requirements or conditions.

4. The permit application forms submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Environmental Article§2-401, Annotated Code of Maryland and Titles IV and V of the Clean Air Act, the Maryland Department of the Environment, Air and Radiation Management Administration issues this permit pursuant to COMAR 26.11.02 and COMAR 26.11.03.

Renewal Permit Approval

George S. Aburn, Jr., Director
Air and Radiation Management Administration

Date of Issue
2. **SO₂ and NOₓ Requirements for each affected unit**

<table>
<thead>
<tr>
<th>SO₂ Requirements</th>
</tr>
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<tbody>
<tr>
<td>SO₂ Allowances for each unit (Units 1, 2, and 3 and GT2 and GT3)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NOₓ Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOₓ Limit</td>
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<tr>
<td>Unit No. 1</td>
</tr>
<tr>
<td>Unit No. 2</td>
</tr>
<tr>
<td>Unit No. 3</td>
</tr>
</tbody>
</table>

3. **Comments, notes and justifications regarding decisions, and changes made to the permit application forms during the review process:**

The allowances allocated by the United States Environmental Protection Agency (U.S. EPA) to each unit are listed in Table 2 of 40 CFR Part 73. However, the number of allowances actually held by an affected source in the unit account may differ from the number allocated by the U.S. EPA.

Pursuant to 40 CFR Part 76 the Maryland Department of the Environment, Air and Radiation Management Administration approves a NOₓ emissions compliance plan for Units 1, 2 and 3 effective for the calendar years of 2008, 2009, 2010, 2011 and 2012. Under this plan the units’ actual annual average NOₓ emission rate shall not exceed the applicable limitation of 0.40 lb/mmBtu as set forth in 40 CFR 76.7(a)(1) for Group 1, Phase II tangentially fired boilers. In addition, Units 1, 2 and 3 shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NOₓ compliance plan and requirements covering excess emissions.

Units GT2 and GT3 burn fuel oil or natural gas. Because these units are not coal fired, the nitrogen oxide emissions reduction regulations of 40 CFR Part 76 are not applicable.

**Renewal Permit Approval**

George S. Aburn, Jr., Director
Air and Radiation Management Administration

Date of Issue
CO₂ BUDGET TRADING PROGRAM PERMIT

<table>
<thead>
<tr>
<th>Plant Name:</th>
<th>Dickerson Generating Station</th>
</tr>
</thead>
<tbody>
<tr>
<td>Affected Trading Units:</td>
<td>Unit 1, Unit 2, Unit 3, and HCT1 and HCT2</td>
</tr>
<tr>
<td>Owner:</td>
<td>GenOn Mid-Atlantic LLC</td>
</tr>
<tr>
<td>Effective Date From:</td>
<td>November 1, 2015  To: October 31, 2020</td>
</tr>
</tbody>
</table>

Contents:

1. Statement of Basis
2. Table of Affected Units
4. The permit application forms submitted for this source.

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Environmental Article §2-401, Annotated Code of Maryland, the Maryland Department of the Environment, Air and Radiation Management Administration issues this permit pursuant to COMAR 26.09.01 thru COMAR 26.09.04.

Initial Permit Approval

______________________________  __________________________
George S. Aburn, Jr., Director                           Date of Issue
Air and Radiation Management Administration
2. Affected Units

<table>
<thead>
<tr>
<th>Unit ID #</th>
<th>ARMA ID #</th>
<th>Unit Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>3-0001</td>
<td>191 MWe coal fired boiler, tangentially fired</td>
</tr>
<tr>
<td>Unit 2</td>
<td>3-0002</td>
<td>191 MWe coal fired boiler, tangentially fired</td>
</tr>
<tr>
<td>Unit 3</td>
<td>3-0003</td>
<td>191 MWe coal fired boiler, tangentially fired 65 MWe (approx) No. 2 fuel oil fired combustion turbine</td>
</tr>
<tr>
<td>HCT1</td>
<td>9-0362</td>
<td>148 MWe (gross-summer) – 168 (gross-winter) dual fuel fired, natural gas primary fuel or No.2 oil fired secondary, simple cycle combustion turbine</td>
</tr>
<tr>
<td>HCT2</td>
<td>9-0363</td>
<td>148 MWe (gross-summer) – 168 (gross-winter) dual fuel fired, natural gas primary fuel or No.2 oil fired secondary, simple cycle combustion turbine</td>
</tr>
</tbody>
</table>

3. Standard Requirements:

(A) Selection and Responsibilities of CO₂ Budget Source Compliance Account Authorized Account Representatives.

(1) Each CO₂ budget source shall have a CO₂ authorized account representative and an alternate CO₂ authorized account representative.
   (COMAR 26.09.01.04B)

(2) Upon receipt of a complete account certificate of representation:

   (a) The CO₂ authorized account representative and alternate CO₂ authorized account representative shall represent and, by representations, actions, inactions, or submissions, legally bind each owner or operator of the CO₂ budget source represented and each CO₂ budget unit at the source in all matters pertaining to this subtitle, notwithstanding any agreement between the CO₂ authorized account representative, alternate CO₂ authorized account representative, and the owners or operators; and
   (COMAR 26.09.01.04E (1))

   (b) The owners or operators shall be bound by any decision or order issued to the CO₂ authorized account representative or alternate CO₂ authorized account representative by the Department or a court regarding the CO₂ budget source or unit.
   (COMAR 26.09.01.04E (2))

(3) A CO₂ budget permit may not be issued or a compliance account established for a CO₂ budget source until the Department has received a complete account certificate of representation for a CO₂ authorized account representative and alternate CO₂ authorized account representative of the source and the CO₂ budget units at the source.
   (COMAR 26.09.01.04F)
(4) Each submission shall be signed and certified by the CO₂ authorized account representative or alternate CO₂ authorized account representative on behalf of each CO₂ budget source and shall include the following statement by the CO₂ authorized account representative or alternate CO₂ authorized account representative: "I am authorized to make the submission on behalf of the owners or operators of the CO₂ budget sources or CO₂ budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in the document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(COMAR 26.09.01.04G)

(B) Distribution Of CO₂ Allowances And Compliance

(1) Unless otherwise specified in this chapter, a CO₂ budget source shall demonstrate compliance with its CO₂ budget emissions limitation by having one CO₂ allowance in its compliance account for every ton of CO₂ that it emits in a control period, by the allowance transfer deadline for that control period.

(COMAR 26.09.02.03E(1))

(2) The following CO₂ allowances may be deducted from a compliance account for purposes of complying with a budget source’s CO₂ budget emissions limitation for a certain control period

(a) CO₂ allowances that are not CO₂ offset allowances and are identified as allowances falling within a prior control period or the same control period for which the allowances are deducted;

(b) CO₂ allowances that are held or transferred into the CO₂ budget source’s compliance account as of the CO₂ allowance transfer deadline for that control period;

(c) CO₂ offset allowances that are available to be deducted for compliance during a control period may not exceed the following:

(i) 3.3 percent;

(ii) 5 percent, if the Department determines that there has been a Stage 1 trigger event; and

(iii) 10 percent, if the Department determines that there has been a Stage 2 trigger event.

(COMAR 26.09.02.03E(2)(a)-(c))

(3) The Department shall deduct CO₂ allowances from the CO₂ budget source’s compliance account until the number of CO₂ allowances deducted equals the number of tons of total CO₂ emissions, less any CO₂ emissions attributable to the burning of eligible biomass.

(COMAR 26.09.02.03E (3))

(4) The identification of available CO₂ allowances for compliance deduction by serial number or by default is as follows:

(a) The CO₂ authorized account representative for a source’s compliance account may request that specific CO₂ allowances, identified by serial number for a control period, be deducted; and

(b) In the absence of an identification or in the case of a partial identification of available CO₂ allowances by serial number, the Department shall deduct CO₂ allowances for a control period in the following descending order:
(i) For the first control period, all CO₂ allowances purchased by direct sale from the Department during years 2009, 2010, and 2011 resulting from the occurrence of the $7 auction clearing price;

(ii) All CO₂ allowances for a control period allocated to a CO₂ budget unit from the Long Term Contract Set-aside Account or the Clean Generation Set-aside Account;

(iii) Subject to the relevant compliance deduction limitations identified in §E(2)(c) of this regulation, any CO₂ offset allowances transferred and recorded in the compliance account, in chronological order; and

(iv) Any CO₂ allowances, other than those identified in §E(4)(b)(i) — (iii) of this regulation, that are available for deduction in the order they were recorded.

(COMAR 26.09.02.03E (4)(a)-(b))

(5) Deductions for Excess Emissions:

(a) If a CO₂ budget source has excess emissions, the Department shall deduct, from the CO₂ budget source’s compliance account, CO₂ allowances from allocation years that occur after the control period in which the source has excess emissions that equal three times the number of the source’s excess emissions.

(b) If a source has insufficient CO₂ allowances to cover three times the number of the source’s excess emissions, the source shall immediately transfer sufficient allowances into its compliance account.

(c) CO₂ offset allowances may not be deducted to account for the source’s excess emissions.

(d) Any CO₂ allowance deduction does not affect the liability of the owners or operators of the CO₂ budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable State law.

(COMAR 26.09.02.03E (5)(a)-(d))

(6) The following guidelines apply in assessing fines, penalties, or other obligations:

(a) For purposes of determining the number of days of violation, if a CO₂ budget unit has excess emissions for a control period, each day in the control period constitutes a day of violation unless the owners or operators of the unit can demonstrate to the satisfaction of the Department that a lesser number of days should be considered; and

(b) The Department shall consider the amount of excess emissions in determining the severity of the violation.

(COMAR 26.09.02.03E (6)(a)-(b))

(7) If the CO₂ budget source’s compliance account no longer exists, the CO₂ allowances shall be deposited in a general account selected by the owner or operator of the CO₂ budget source.

(COMAR 26.09.02.03E (7))

(8) Adjustments and Errors:

(a) The Department may review and conduct independent audits concerning any submission under this subtitle and make appropriate adjustments of the information, if necessary.
(b) The Department may correct any error in any account and, within 10 business days of making any correction, notify the CO₂ authorized account representative for the account

(ComAR 26.09.02.03E (8)(a)-(b))

(C) Applicability and Administration

(1) The requirements of this permit apply to the owner or operator of a CO₂ budget unit. When this permit establishes a requirement such as the submittal of a permit application, a report, a request for allowances or transfer of allowances, or general information, these actions shall be achieved through the authorized account representative on behalf of the owner or operator of the affected CO₂ budget source or unit.

(ComAR 26.09.02.02A)

(2) The requirements of this subtitle are effective on January 1, 2009 or, for new CO₂ budget units, on the day on which the unit commences operation.

(ComAR 26.09.02.02C).

(3) The provisions of this permit do not exempt or otherwise relieve the owners or operators of a CO₂ budget source from achieving compliance with any other provision of applicable State and federal laws and regulations.

(ComAR 26.09.02.02D).

(4) Unless otherwise stated under this subtitle, any time period scheduled to begin:

(a) On the occurrence of an act or event, begins on the day the act or event occurs; and

(b) Before the occurrence of an act or event, is computed so that the period ends the day before the act or event occurs.

(ComAR 26.09.02.02F)

(5) Unless otherwise stated, if the final day of any time period for performing an act required by this subtitle falls on a weekend or on a State or federal holiday, the time period is extended until or to the next business day.

(ComAR 26.09.02.02G)

(D) Permit Requirements

(1) The account representative or designate alternate account representative) of each affected unit at a source, (every fossil fuel fired unit with a nameplate capacity of 25 MW or greater) for that source shall comply with the following:

(a) The CO₂ authorized account representative for the source shall submit an initial CO₂ budget permit application by October 1, 2008, or 12 months before the date on which the CO₂ budget source, or a new unit at the source, commences operation.

(ComAR 26.09.02.04A (2));

(b) The CO₂ budget permit application shall include the following in a format prescribed by the Department: 1) the identification of the CO₂ budget source; 2) facility name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U. S. Department of Energy, if applicable; 3) each CO₂ budget unit at the source; and 4) other information required by the Department.

(ComAR 26.09.02.04A (3))
(c) The authorized account representative for the source shall submit a complete application for the renewal of an existing CO$_2$ budget permit on forms provided by the Department not later than 90 days before the expiration of the current CO$_2$ budget permit.  
(COMAR 26.09.02.04 E)

(2) Each CO$_2$ budget source shall apply for and have in effect a CO$_2$ budget permit that contains all applicable requirements.  
(COMAR 26.09.02.04A (1)).

(3) The CO$_2$ budget permit issued by the Department shall be separate but attached to the budget source’s Part 70 permit.  
(COMAR 26.09.02.04B)

(4) A CO$_2$ budget permit expires 5 years from the date of issuance by the Department, unless an earlier expiration date is specified in the permit.  
(COMAR 26.09.02.04D)

(E) Monitoring, Initial Certification and Recertification Requirements

(1) For each control period in which a CO$_2$ budget source is subject to the CO$_2$ budget emissions limitation, the CO$_2$ authorized account representative of the source shall submit a compliance certification report by the March 1 following the relevant control period.  
(COMAR 26.09.02.05 A (1))

(2) The CO$_2$ authorized account representative shall include in the compliance certification report the following:

(a) Identification of the source and each CO$_2$ budget unit at the source;

(b) At the CO$_2$ authorized account representative's option, the serial numbers of the CO$_2$ allowances that are to be deducted from the source’s compliance account for the control period, including the serial numbers of any CO$_2$ offset allowances that are to be deducted subject to applicable limitations; and

(c) The compliance certification required by §A(3) of COMAR 26.11.02.05.  
(COMAR 26.09.02.05 A (2))

(3) In the compliance certification report, the CO$_2$ authorized account representative shall certify whether the source and each CO$_2$ budget unit at the source for which the compliance certification is submitted was operated during the control period in compliance with the requirements of this subtitle, including:

(a) Whether each CO$_2$ budget unit at the source was operated in compliance with the CO$_2$ budget emissions limitation;
(b) Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit and contains all information necessary to track CO₂ emissions from the unit;

(c) Whether all CO₂ emissions from each unit at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including: identification of all conditional data reported in the quarterly reports; and if conditional data were reported, whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

(d) Whether the basis for certification or for using an excepted monitoring method or approved alternative monitoring method has changed;

(e) If a change is required to be reported, include: the nature and reasons for the change; when the change occurred; and how the unit's compliance status was determined after the change, including the method used to determine emissions when a change mandated the need for monitor recertification.

(COMAR 26.09.02.05A (3) (a)-(e))

(4) The Department, at its discretion, may review and conduct independent audits of any compliance certification or other submission required by this permit.

(COMAR 26.09.02.05 B (1))

(5) The Department may deduct CO₂ allowances from, or transfer CO₂ allowances to, a compliance account to correct errors in the account or to accurately reflect CO₂ emissions, based on the information in the compliance certification or other submissions.

(COMAR 26.09.02.05 B (2))

(6) The owner or operator of a CO₂ budget unit shall:

(a) Install monitoring systems to monitor CO₂ concentration, stack gas flow rate, oxygen concentration, heat input, and fuel flow rate;

(b) Install all monitoring systems in accordance with 40 CFR Part 75, except for equation G-1 in Appendix G (see below); and

\[ W_{CO_2} = \frac{(MW_C + MW_{O_2}) \times W_C}{2,000 MW_C} \quad (Eq. \ G-1) \]

Where:

\[ W_{CO_2} = \text{CO}_2 \text{ emitted from combustion, tons/day.} \]

\[ MW_C = \text{Molecular weight of carbon (12.0).} \]

\[ MW_{O_2} = \text{Molecular weight of oxygen (32.0).} \]
Wc = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates.

(c) Record, report, and verify the data from the monitoring systems.
   (COMAR 26.09.02.10A (1) (a)-(c))

(7) Install and certify the monitoring system on or before the following dates:

   (a) For a CO₂ budget unit that commences commercial operation before July 1, 2008, the owner or operator shall comply on or before January 1, 2009; and

   (b) For a CO₂ budget unit that commences commercial operation or constructs a new stack or flue on or after July 1, 2008, the owner or operator shall comply by January 1, 2009, or 90 operating days after the date on which the unit commences commercial operation.
   (COMAR 26.09.02.10 A (1) (d))

(8) The owner or operator of a CO₂ budget unit that does not meet the applicable compliance date shall, in accordance with the provisions in 40 CFR §75.31(b)(2) or (c)(3), or §2.4 of Appendix D, determine, record, and report maximum potential or, as appropriate, minimum potential for the following:

   (a) CO₂ concentration;

   (b) CO₂ emissions rate;

   (c) Stack gas moisture content;

   (d) Fuel flow rate; and

   (e) Any other parameter required to determine CO₂ mass emissions.
   (COMAR 26.09.02.10 A (2) (a)-(e))

(9) The owner or operator of a CO₂ budget unit that does not meet the applicable compliance date for any monitoring system shall determine, record, and report substitute data using the applicable missing data procedures in 40 CFR Part 75 Subpart D, or Appendix D, instead of the maximum potential values or, as appropriate, minimum potential values for a parameter, if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation.
   (COMAR 26.09.02.10 A (3))

(10) An owner or operator of a CO₂ budget unit or a non-CO₂ budget unit monitored under 40 CFR §75.72 (b) (2) (ii) may not:

   (a) Use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emissions monitoring system without having obtained prior written approval from the Department;
(b) Operate the unit so as to discharge, or allow to be discharged, CO\textsubscript{2} emissions to the atmosphere without accounting for all emissions in accordance with the applicable provisions of this chapter and 40 CFR Part 75;

(c) Disrupt the operation of the CEMS, any portion of the CEMS, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO\textsubscript{2} mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed; or

(e) Permanently discontinue use of the approved CEMS unless the owner or operator monitors emissions with a system approved in accordance with this chapter and 40 CFR Part 75. (COMAR 26.09.02.10 A (4) (a)-(e))

(11) For purposes of this subtitle only, the owner or operator of a CO\textsubscript{2} budget unit is exempt from demonstrating compliance with the initial certification requirements of 40 CFR §75.20 for a monitoring system if the following conditions are met:

(a) The monitoring system has been previously certified in accordance with 40 CFR §75.20; and

(b) The applicable quality assurance and quality-control requirements of 40 CFR §75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system. (COMAR 26.09.02.10 B (1) (a)-(b))

(12) The recertification provisions of this regulation apply to a monitoring system exempt from the initial certification requirements of this regulation. (COMAR 26.09.02.10 B (2))

(13) If the Department has previously approved a petition under 40 CFR §75.72(b)(2)(ii) or 40 CFR §75.16(b)(2)(ii)(B) pursuant to 40 CFR §75.13 for apportioning the CO\textsubscript{2} emissions rate measured in a common stack or a petition under 40 CFR §75.66 for an alternative requirement in 40 CFR Part 75, the CO\textsubscript{2} authorized account representative shall resubmit the petition to the Department to determine whether the approval applies under this chapter. (COMAR 26.09.02.10 B (3))

(14) The owner or operator of a CO\textsubscript{2} budget unit shall comply with the initial certification and recertification procedures for a CEMS and an excepted monitoring system under 40 CFR Part 75, Appendix D. (COMAR 26.09.02.10 B (4))

(15) The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR §75.19 or that qualifies to use an alternative monitoring system under 40 CFR Part 75, Subpart E, shall comply with this regulation. (COMAR 26.09.02.10 B (5))

(16) When the owner or operator replaces, modifies, or changes a CEMS that the Department determines significantly affects the ability of the system to accurately measure or record CO\textsubscript{2} emissions to the atmosphere without accounting for all emissions in accordance with the applicable provisions of this chapter and 40 CFR Part 75;
mass emissions or to meet the quality assurance and quality control requirements of 40 CFR §75.21 or Appendix B, the owner or operator shall recertify the monitoring system according to 40 CFR §75.20(b).

(COMAR 26.09.02.10 C (1))

(17) When the owner or operator replaces, modifies, or changes the flue gas handling system or the unit’s operation in a manner that the Department determines has significantly changed the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR §75.20(b).

(COMAR 26.09.02.10 C (2))

(18) Approval Process for Initial Certifications and Recertification. The procedures in 40 CFR §75.20(b)(5) and (g)(7) apply for recertification. The CO$_2$ authorized account representative shall submit to the Department:

(a) A written notice of the dates of certification; and

(b) A recertification application for each monitoring system, including the information specified in 40 CFR §75.63.

(COMAR 26.09.02.10 C(3) (a)-(b))

(19) Provisional certification data for a monitor shall be:

(a) Determined in accordance with 40 CFR §75.20(a)(3);

(b) A provisionally certified monitor may be used for a period not to exceed 120 days after receipt of the complete certification application for the monitoring system or component; and

(c) Data measured and recorded by the provisionally certified monitoring system or component is considered valid quality assured data, retroactive to the date and time of provisional certification, if the Department does not issue a notice of disapproval within 120 days of receipt of the complete certification application.

(COMAR 26.09.02.10 C (4) (a)-(c))

(20) The Department shall issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application.

(COMAR 26.09.02.10 D (1))

(21) If the Department does not issue the notice within the 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application shall be deemed certified for use.

(COMAR 26.09.02.10 D (2))

(22) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, the Department shall issue a written notice of approval of the certification application within 120 days of receipt.

(COMAR 26.09.02.10 D (3))
(23) If the certification application is not complete, the Department shall issue a written notice of incompleteness that sets a reasonable date by which the CO₂ authorized account representative is to submit the additional information required to complete the certification application.
   (COMAR 26.09.02.10 D (4))

(24) If the CO₂ authorized account representative does not comply with the notice of incompleteness by the specified date, the Department may issue a notice of disapproval.
   (COMAR 26.09.02.10 D (5))

(25) If the Department issues a notice of disapproval of a certification application or a notice of disapproval of certification status, the owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR §75.20(a)(5)(i) or 75.20(g)(7):

   (a) For units using or intending to monitor for CO₂ mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR §75.19, the maximum potential hourly heat input of the unit; or

   (b) For units intending to monitor for CO₂ mass emissions using a CO₂ pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO₂ and the maximum potential flow rate of the unit under 40 CFR Part 75, Appendix A, §2.1.
   (COMAR 26.09.02.10 D (6) (a)-(b))

(26) The CO₂ authorized account representative shall submit a notification of certification retest dates and a new certification application. The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Department's notice of disapproval, not later than 30 operating days after the date of issuance of the notice of disapproval.
   (COMAR 26.09.02.10 D (7))

(27) The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 40 CFR §75.19 shall meet the applicable certification and recertification requirements of 40 CFR §§75.19(a) (2) and 75.20(h).
   (COMAR 26.09.02.10 E (1))

(28) If the owner or operator of this unit elects to certify a fuel flow meter system for heat input determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR §75.20(g).
   (COMAR 26.09.02.10 E (2))

(29) Certification and Recertification Procedures for Alternative Monitoring Systems. For each unit for which the owner or operator intends to use an alternative monitoring system approved by the Department, 40 CFR Part 75, Subpart E, shall be used to comply with the applicable notification and application procedures of 40 CFR §75.20(f).
   (COMAR 26.09.02.10 F)
(30) When any monitoring system fails to meet the quality assurance and quality control requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in 40 CFR Part 75, Subpart D, Appendix D.

  (COMAR 26.09.02.10 G (1))

(31) Audit Decertification.

  (a) Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the Department shall issue a notice of disapproval of the certification status of the monitoring system.

  (b) By issuing the notice of disapproval, the certification status of the monitoring system is prospectively revoked.

  (COMAR 26.09.02.10 G (2))

(32) The data measured and recorded by the monitoring system may not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status.

  (COMAR 26.09.02.10 G (3))

(F) Record Keeping and Reporting Requirements

(1) The CO₂ authorized account representative shall comply with all record-keeping and reporting requirements in COMAR 26.09.02.10 and the applicable record-keeping and reporting requirements under 40 CFR §75.73.

  (COMAR 26.09.02.11 A)

(2) The CO₂ authorized account representative shall submit quarterly reports as described below in this section.

  (COMAR 26.09.02.11 B (1))

(3) The report shall contain the CO₂ mass emissions data for the CO₂ budget unit in an electronic format, unless otherwise required by the Department, for each calendar quarter beginning with:

  (a) The calendar quarter covering January 1, 2009 — March 31, 2009, for a unit that commences commercial operation before July 1, 2008; or

  (b) For a unit commencing commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the following dates: date of provisional certification; or applicable deadline for initial certification.

  (c) If the quarter is the third or fourth quarter of 2008, reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

  (COMAR 26.09.02.11 B (2) (a)-(b))

(4) The CO₂ authorized account representative shall submit each quarterly report within 30 days following
the end of the calendar quarter covered by the report and in accordance with 40 CFR Part 75, Subpart H, §75.64 and 40 CFR Part 75, Subpart G except for the opacity, NOX and SO2 provisions.

(COMAR 26.09.02.11 B (4))

(5) The CO2 authorized account representative shall submit a compliance certification in support of each quarterly report. The certification shall state that:

(a) The monitoring data submitted were recorded in accordance with the applicable requirements of this chapter and 40 CFR Part 75, including the quality assurance procedures and specifications;

(b) For a unit with add-on CO2 emissions controls and for all hours where data are substituted in accordance with 40 CFR §75.34(a)(1), the add-on emissions controls were operating within the range of parameters listed in the quality assurance and quality control program under 40 CFR Part 75, Appendix B, and the substitute values do not systematically underestimate CO2 emissions; and

(c) The CO2 concentration values substituted for missing data under 40 CFR Part 75, Subpart D, do not systematically underestimate CO2 emissions.

(COMAR 26.09.02.11 B (5) (a)-(c))

(6) The CO2 authorized account representative of a CO2 budget unit may submit a petition to the Department under 40 CFR §75.66 requesting approval to apply an alternative to any requirement of this chapter.

(COMAR 26.09.02.11 C)

(7) The CO2 authorized account representative or alternate CO2 authorized account representative of a CO2 budget unit that burns eligible biomass as a compliance mechanism under this chapter shall report the following information for each calendar quarter:

(a) For each shipment of solid eligible biomass fuel fired at the CO2 budget unit:
   (i) Total eligible biomass fuel input, on an as-fired basis, in pounds; and
   (ii) The moisture content, on an as-fired basis, as a fraction of weight;

(b) For each distinct type of gaseous eligible biomass fuel fired at the CO2 budget unit:
   (i) The density of the biogas, on an as-fired basis, in pounds per standard cubic foot; and
   (ii) The moisture content of the biogas, as a fraction by total weight;

(c) For each distinct type of eligible biomass fuel fired at the CO2 budget unit:
   (i) The dry basis carbon content of the fuel type, as a fraction by dry weight;
   (ii) The dry basis higher heating value, in MMBtu per dry pound;
   (iii) The total dry basis eligible biomass fuel input, in pounds;
Dickerson Generating Station
GenOn Mid-Atlantic LLC

CO₂ Budget Trading Program Permit

(iv) The total eligible biomass fuel heat input; and

(v) Chemical analysis, including heat value and carbon content;

(d) The total amount of CO₂ emitted from the CO₂ budget unit due to firing eligible biomass fuel, in tons, calculated as in §D(2)(b) of this regulation;

(e) The total heat input to the CO₂ budget unit due to firing eligible biomass fuel, in MMBtu, calculated below; and

(f) Description and documentation of monitoring technology and fuel sampling methodology employed, including sampling frequency.

(COMAR 26.09.02.11 D (1) (a)-(f))

(8) An owner or operator of a CO₂ budget unit shall calculate and submit on a quarterly basis the total dry weight for each distinct type of eligible biomass fired by the CO₂ budget unit during the reporting quarter:

(a) For solid eligible biomass fuel, determined as follows:

\[ F_j = \sum_{i=1}^{m} (1 - M_i) x F_i \]

where:
(i) \( F_j \) = Total eligible biomass dry basis fuel input (pounds) for fuel type \( j \);
(ii) \( F_i \) = Eligible biomass as fired fuel input (pounds) for fired shipment \( i \);
(iii) \( M_i \) = Moisture content (fraction) for fired shipment \( i \);
(iv) \( i \) = fired fuel shipment;
(v) \( j \) = fuel type; and
(vi) \( m \) = number of shipments.

(b) For gaseous eligible biomass fuel, as determined as follows:

\[ F_j = D_j x V_j x (1 - M_j) \]

where:
(i) \( F_j \) = Total eligible biomass dry basis fuel input (pounds) for fuel type \( j \);
(ii) \( D_j \) = Density of biogas (pounds/scf) for fuel type \( j \);
(iii) \( V_j \) = Total volume (scf) for fuel type \( j \);
(iv) \( M_j \) = Moisture content (fraction) for fuel type \( j \); and
(v) \( j \) = fuel type

(COMAR 26.09.02.11 D (2) (a)-(b))

(9) The amount of CO₂ emissions that is produced from the firing of eligible biomass for any full calendar quarter, during which either no fuel other than eligible biomass is combusted or during which fuels other than eligible biomass are combusted, is determined as follows:
\[ CO_2\text{tons} = \sum_{j=1}^{n} F_j x C_j x O_j \left( \frac{44}{molCO_2} \right) \left( \frac{g}{molC} \right) \left( 0.0005 \right) \]

where:
(a) \( CO_2 \) tons = \( CO_2 \) emissions due to firing of eligible biomass for the reporting quarter;
(b) \( F_j \) = Total eligible biomass dry basis fuel input (pounds) for fuel type \( j \), as calculated in §D(2)(a) of this regulation;
(c) \( C_j \) = Carbon fraction (dry basis) for fuel type \( j \);
(d) \( O_j \) = Oxidation factor for eligible biomass fuel type \( j \), derived for solid fuels based on the ash content of the eligible biomass fired and the carbon content of this ash or for gaseous eligible biomass fuels, a default oxidation factor of 0.995 may be used;
(e) \( \frac{44}{molCO_2} \left( \frac{g}{molC} \right) \left( 0.0005 \right) \) = The number of tons of carbon dioxide that are created when one ton of carbon is combusted;
(f) 0.0005 = The number of short tons which is equal to one pound;
(g) \( j \) = Fuel type; and
(h) \( n \) = number of distinct fuel types.

(10) Heat input due to firing of eligible biomass for each quarter shall be determined as follows:
(a) For each distinct fuel type:
\[ H_j = F_j x HHV_j \]

where:
(i) \( H_j \) = Heat input (MMBtu) for fuel type \( j \);
(ii) \( F_j \) = Total eligible biomass dry basis fuel input (pounds) for fuel type \( j \);
(iii) \( HHV_j \) = Higher heating value (MMBtu/pound), dry basis, for fuel type \( j \), as determined through chemical analysis;
(iv) \( j \) = Fuel type.

(b) For all fuel types:
\[ HeatInputMMBtu = \sum_{j=1}^{n} H_j \]
where:
(i) $H_j =$ Heat input (MMBtu) for fuel type $j$;  
(ii) $j =$ fuel type; and 
(iii) $n =$ number of distinct fuel types.

Fuel sampling methods and fuel sampling technology shall be consistent with the New York State Renewable Portfolio Standard Biomass Guidebook, May 2006.  
(COMAR 26.09.02.11D(4) & D(5))

(11) A CO$_2$ budget unit shall submit to the Department the megawatt-hour value and a statement certifying that the megawatt-hour of electrical output reported reflects the total actual electrical output for all CO$_2$ budget units at the facility used by the independent system operator (ISO) to determine settlement resources of energy market participants.  
(COMAR 26.09.02.11 E (1))

(12) A CO$_2$ budget unit shall report gross hourly megawatts to the Department in the same electronic data report (EDR) for gross output as submitted to the EPA Administrator, for the operating time in the hour, added for all hours in a year.  
(COMAR 26.09.02.11 E (2))

(13) A CO$_2$ budget unit shall submit the net electrical output to the Department in accordance with this regulation.  A CO$_2$ budget source whose electrical output is not used in the independent system operator (ISO) energy market settlement determinations shall propose a method for quantification of net electrical output.  
(COMAR 26.09.02.11 E (3))


(a) CO$_2$ budget sources selling steam shall use billing meters to determine net steam output or an alternative method to measure net steam output approved by the Department.

(b) If data for steam output is not available, the CO$_2$ budget source may report heat input, substituting useful steam output for steam output.  
(COMAR 26.09.02.11 E (4) (a)-(b))

(15) Each CO$_2$ budget source shall submit an output monitoring plan with a description and diagram that include the following:

(a) If the CO$_2$ budget unit monitors net electric output, the diagram shall contain all CO$_2$ budget units and all generators served by each CO$_2$ budget unit and the relationship between CO$_2$ budget units and generators;

(b) If a generator served by a CO$_2$ budget unit is also served by a nonaffected unit, the nonaffected unit and its relationship to each generator shall be indicated on the diagram;

(c) The diagram shall indicate where the net electric output is measured and include all electrical inputs and
outputs to and from the plant;

(d) If net electric output is determined using a billing meter, the diagram shall show each billing meter used to determine net sales of electricity and show that all electricity measured at the point of sale is generated by the CO₂ budget units;

(e) If the CO₂ budget unit monitors net thermal output, the diagram shall indicate all steam or hot water coming into the net steam system, including steam from CO₂ budget units and nonaffected units, and all exit points of steam or hot water from the net steam system;

(f) Each input and output stream shall have an estimated temperature, pressure and phase indicator, and an enthalpy in Btu per pound;

(g) The diagram of the net steam system shall identify all useful loads, house loads, parasitic loads, any other steam loads, and all boiler feedwater returns;

(h) The diagram shall represent all energy losses in the system as either usable or unusable losses;

(i) The diagram shall indicate all flow meters, temperature or pressure sensors, or other equipment used to calculate gross thermal output; and

(j) If a sales agreement is used to determine net thermal output, the diagram shall show the monitoring equipment used to determine the sales of steam.

(COMAR 26.09.02.11 F (2) (a)-(j))

(16) The description of the output monitoring system shall include:

(a) A written description of the output system and the equations used to calculate output, and, for net thermal output systems, descriptions and justifications of each useful load;

(b) A detailed description of all quality assurance and quality control activities that will be performed to maintain the output system; and

(c) Documentation supporting any output value to be used as a missing data value if there are periods of invalid output data.

(d) The missing data output value shall be either zero or an output value that is likely to be lower than a measured value and approved as part of the required monitoring plan.

(COMAR 26.09.02.11 F (3) (a)-(b))

(17) A certification statement shall be submitted by the CO₂ authorized account representative stating that either:

(a) The output monitoring system consists entirely of billing meters; or

(b) The output monitoring system meets one of the accuracy requirements for nonbilling meters.

(COMAR 26.09.02.11 G (1) (a)-(b))
(18) The billing meter shall record the electric or thermal output. Any electric or thermal output values reported shall be the same as the values used in billing for the output.
   (COMAR 26.09.02.11 G (2))

(19) For nonbilling meters, either the output monitoring system shall meet an accuracy of within 10 percent of the reference value, or each component monitor for the output system shall meet an accuracy of within 3 percent of the full scale value, whichever is less stringent.
   (COMAR 26.09.02.11 G (3))

(20) The system approach to accuracy shall include:
   
   (a) A determination of how the system accuracy of 10 percent is achieved using the individual components in the system; and
   
   (b) Data loggers and any wattmeters used to calculate the final net electric output data or any flowmeters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices used for measuring thermal energy.
   (COMAR 26.09.02.11 G (4) (a)-(b))

(21) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to within 3 percent of the full scale value, then the equipment shall be repaired or replaced to meet that requirement.
   (COMAR 26.09.02.11 G (5))

(22) Data is invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.
   (COMAR 26.09.02.11 G (6))

(23) Ongoing quality assurance and quality control activities shall be performed in order to maintain the output system.
   (COMAR 26.09.02.11 H (1))

(24) If billing meters are used to determine output, quality assurance and quality control activities are not required beyond what are already performed.
   (COMAR 26.09.02.11 H (2))

(25) Certain types of equipment such as potential transformers, current transformers, nozzle and venture type meters, and the primary element of an orifice plate only require an initial certification of calibration and do not require periodic recalibration unless the equipment is physically changed.

   (a) Pressure and temperature transmitters accompanying an orifice plate will require periodic retesting.

   (b) For other types of equipment, the meter accuracy shall be recalibrated or verified at least once every 2 years, unless a consensus standard allows for less frequent calibrations or accuracy tests.

   (c) For nonbilling meters, either the output monitoring system shall meet an accuracy of within 10 percent
of the reference value, or each component monitor for the output system shall meet an accuracy of within 3 percent of the full scale value, whichever is less stringent.

(d) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to within 3 percent of the full scale value, then the equipment shall be repaired or replaced to meet that requirement.

(COMAR 26.09.02.11 H (3) (a)-(e))

(26) Out-of-Control Periods.

(a) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to the certification value, data is invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.

(b) All invalid data shall be replaced by either zero or an output value that is likely to be lower than a measured value and that is approved as part of the required monitoring plan.

(COMAR 26.09.02.11 H (4) (a)-(b))

(27) The CO₂ authorized account representative shall submit annual output reports, as follows:

(a) Data shall be sent both electronically and in hardcopy by March 1 for the immediately preceding calendar year; and

(COMAR 26.09.02.11 I (1))

(28) The annual report shall include unit level megawatt hours, all useful steam output, and a certification statement from the CO₂ authorized account representative stating the following, “I am authorized to make this submission on behalf of the owners and operators of the CO₂ budget sources or CO₂ budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(COMAR 26.09.02.11 I (2))

(G) CO₂ Emission Offset Projects

(1) In order to qualify for the award of CO₂ offset allowances, the following offset projects shall satisfy all applicable requirements identified in COMAR 26.09.03 and initially commence on or after December 20, 2005:

(a) Landfill methane capture and destruction;

(b) Reduction in emissions of sulfur hexafluoride (SF₆);

(c) Sequestration of carbon due to afforestation;
(d) Reduction or avoidance of CO\textsubscript{2} emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency; and

(e) Avoided methane emissions from agricultural manure management operations.  
(COMAR 26.09.03.01 A (1)-(5))

4. Permit Application (See Attachment)
BACKGROUND

The Dickerson Generating Station is engaged in the generation of electric energy for sale. The primary SIC code for this facility is 4911. The major components of the facility consist of three (3) steam units primarily firing bituminous coal, an oil fired combustion turbine primarily used for black start and peaking service, and two (2) peaking service combustion turbines primarily firing natural gas that are all located on site at Station H.

Each of the three (3) boilers, manufactured by Combustion Engineering, Inc. (Alstom) is rated at 191 megawatts. The boilers are tangentially coal fired, with a superheater, re heater, and economizer. Each boiler is equipped with its own ESP and SNCR system. In addition there is a common baghouse and FGD system for all three units. When the FGD is in operation all three units exhaust through a common 400 foot high wet stack. When the FGD is not in operation all three units exhaust through a common 700 foot high dry stack.

The single black start combustion turbine (CT), manufactured by Pratt & Whitney is used both for black start capability and peaking service. The combustion turbine is No. 2 oil fired and rated at 18 megawatts.

The two (2) combustion turbines manufactured by General Electric are used for peaking capacity. Each is rated at 167 megawatts and fires primarily natural gas and No. 2 fuel oil as secondary fuel, and each have a nominal capacity of 167 megawatts. Each combustion turbine’s emissions exhaust through a 213-foot stack.

The following table summarizes the actual emissions from Dickerson Generating Station based on its Annual Emission Certification Reports:

Table 1: Actual Emissions

<table>
<thead>
<tr>
<th>Year</th>
<th>NOX (TPY)</th>
<th>SOX (TPY)</th>
<th>PM10/PM2.5 (TPY)</th>
<th>CO (TPY)</th>
<th>VOC (TPY)</th>
<th>Total HAP (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>1686</td>
<td>686</td>
<td>63/33</td>
<td>184</td>
<td>18</td>
<td>18</td>
</tr>
<tr>
<td>2013</td>
<td>1625</td>
<td>862</td>
<td>13/12</td>
<td>109</td>
<td>11</td>
<td>16</td>
</tr>
<tr>
<td>2012</td>
<td>1489</td>
<td>818</td>
<td>17/12</td>
<td>130</td>
<td>12</td>
<td>18</td>
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<tr>
<td>2011</td>
<td>1907</td>
<td>1145</td>
<td>17/11</td>
<td>145</td>
<td>15</td>
<td>22</td>
</tr>
<tr>
<td>2010</td>
<td>3862</td>
<td>2628</td>
<td>72/44</td>
<td>302</td>
<td>29</td>
<td>756</td>
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<tr>
<td>2009</td>
<td>3243</td>
<td>25717</td>
<td>256/148</td>
<td>234</td>
<td>23</td>
<td>0.21</td>
</tr>
</tbody>
</table>
The major source threshold for triggering Title V permitting requirements in Montgomery County is 25 tons per year for VOC and NO\textsubscript{X}, 100 tons per year for any other criteria pollutants and 10 tons for a single HAP or 25 tons per year for total HAPs. Since the actual NO\textsubscript{X}, SO\textsubscript{X}, and PM\textsubscript{10} emissions from the facility are greater than the major source threshold, Dickerson Generating Station is required to obtain a Title V – Part 70 Operating Permit under COMAR 26.11.03.01.

The Department, on December 4, 2012, received the Dickerson Generating Station’s Part 70-permit renewal application, which was submitted by GenOn Mid-Atlantic, LLC. An administrative completeness review was conducted and the application was deemed complete. A completeness determination letter was sent to GenOn Mid-Atlantic, LLC on December 12, 2012 granting Dickerson Generating Station an application shield.

**CHANGES AND MODIFICATIONS TO THE PART 70 OPERATING PERMIT**

The following changes and/or modifications have been incorporated into the renewal Title V – Part 70 Operating Permit for GenOn Dickerson Generating Station:

**Additions to the facility**

On October 16, 2008, GenOn received a CPCN (Case No. 9140) for the Dickerson SNCR Project that include a Selective Non-Catalytic Reduction (SNCR) control system on Dickerson Units 1, 2, and 3 consisting of urea injectors on boilers and associated ancillary equipment. The SNCR system will be operated as necessary to reduce emissions of nitrogen oxides (NO\textsubscript{X}) to comply with the requirements of Maryland’s Healthy Air Act (HAA) and the NO\textsubscript{X} Reduction and Trading Program. The SNCR completion date startup was June 2009.

**Removal from the facility**

On November 1, 2007, the 20,000 gallon underground gasoline storage tank (Registration #9-0363) was removed and replaced with a 2,000 gallon aboveground gasoline storage tank (not requiring registration due to the size of the tank).

**Name Change**

On January 25, 2011, GenOn Mid-Atlantic LLC notified the Department that they merged with RRI Energy Inc. to form GenOn Energy Inc. and will be trading as GenOn Mid-Atlantic, LLC. Effective December 4, 2012, NRG Energy, Inc. (NRG) and GenOn Energy Inc. (GenOn) have combined and will retain the name NRG Energy, Inc. As a result of the merger, all GenOn entities are now wholly owned subsidiaries of NRG.
MACT and NSPS
Dickerson Generating Station is a major source of HAPs and is subject to the following MACT standards (40 CFR Part 63):

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants:
- Coal- and Oil-Fired Electric Utility Steam Generating Units (D-1, D-2 and D-3)

Dickerson Generating Station is subject to NSPS (40 CFR Part 60), Subpart GG—Standards of Performance for Stationary Gas Turbines (H CT-1 & H CT-2).

Dickerson Generating Station is subject to the NO$_X$ Reasonably Available Control Technology (RACT) requirements and Acid Rain Program. Dickerson Generating Station is also subject to the requirements of the Regional Greenhouse Gas Initiative (RGGI) program which is a State-only enforceable program. Under these regulations, GenOn is required to submit a RGGI permit application. The renewal RGGI permit upon issuance will be attached to the Part 70 permit.

Cross-State Air Pollution Rule (CSAPR)
The U.S. Environmental Protection Agency (EPA) issued the Cross-State Air Pollution Rule (CSAPR) in July 2011 to address Clean Air Act requirements concerning interstate transport of air pollution and to replace the previous Clean Air Interstate Rule (CAIR) which the D.C. Circuit remanded to the EPA for replacement. Following the original rulemaking, CSAPR was amended by three further rules known as the Supplemental Rule, the First Revisions Rule, and the Second Revisions Rule. As amended, CSAPR requires 28 states to limit their state-wide emissions of sulfur dioxide (SO$_2$) and/or nitrogen oxides (NO$_X$) in order to reduce or eliminate the states’ contributions to fine particulate matter and/or ground-level ozone pollution in other states. The emissions limitations are defined in terms of maximum state-wide “budgets” for emissions of annual SO$_2$, annual NO$_X$, and/or ozone season NO$_X$ by each state’s large electricity generating units (EGUs). The emissions budgets are implemented in two phases of generally increasing stringency. As the mechanism for achieving compliance with the emissions limitations, CSAPR establishes federal implementation plans (FIPs) that require large EGUs in each affected state to participate in one or more new emission trading programs that supersede the existing CAIR emissions trading programs. On December 30, 2011, in response to petitions challenging CSAPR, the D.C. Circuit granted a stay of the rule, ordering the EPA to continue administering CAIR on an interim basis. In a subsequent decision, the Court vacated CSAPR but on April 29, 2014, the U.S. Supreme Court reversed that decision and remanded the case to the D.C. Circuit Court for further proceedings. In order to allow CSAPR to replace CAIR in an orderly manner, EPA filed a motion asking the D.C. Circuit to lift the stay and to toll, by three years, all CSAPR compliance deadlines that had not yet passed. On October 23, 2014, the Court granted the EPA’s motion.
Consistent with the Court’s order, compliance with CSAPR’s Phase 1 emissions budgets is now required in 2015 and 2016 and compliance with the rule’s Phase 2 emissions budgets and assurance provisions is now required in 2017 and beyond.

This renewal Part 70 permit identifies the applicable regulations of the CSAPR rule as found in 40 CFR Part 97 subparts AAAAA- NO<sub>x</sub> Annual Trading Program, subparts BBBBB- NO<sub>x</sub> Ozone Season Trading Program, and subpart CCCCC SO<sub>2</sub> Group 1 Trading Program.

**By-Pass Stack Operation**

There are several operating scenarios where the Dickerson bypass stack must run for equipment and/or operator safety reasons. The Flue Gas Desulfurization (FGD) system installed at the plant extended the boiler flue gas path substantially. New ductwork and scrubber vessel added a significant pressure drop to the system which is overcome by a pair of axial booster fans just upstream of the scrubber. This configuration is sensitive to pressure excursions, and the bypass stack acts as a “safety valve” to relieve high or low pressure excursions.

**Scrubber Trip:** when the scrubber trips, such as when a booster fan shuts down suddenly, flue gas flowing from the boilers has nowhere to go, causing duct pressure to build up quickly. Opening the bypass stack relieves this unsafe pressure excursion and allows the units to continue to generate electricity while the trip is investigated. In cases where the scrubber can be returned to service quickly, the plant can resume normal operations much more rapidly than if the units were tripped and restarted.

**Unit Start Up:** whenever a unit starts up, NFPA rules require a gas path to atmosphere and minimum air flow be established before putting a fire in the boiler. The bypass stack is used for this purpose because the FGD booster fans are not stable at the low air flow rates needed for boiler light off.

**Transition from 1 to 2 Booster Fans:** The booster fans are sized to allow for two-unit operation on one fan; however two fans are needed to run three units. The fans are configured to run in parallel in the flue gas ductwork. When transitioning from one to two fan operation, the fans must be allowed to equalize flow between them. To accomplish this, the bypass stack is opened, allowing the running fan to reduce flow while the starting fan picks up speed. Performing this operation with the bypass damper shut can cause flow recirculation between the booster fans, resulting in a pressure excursion.

**Unit Shutdown:** Any time the plant shuts down from a single unit operation, the bypass stack is opened to vent residual flue gases and purge the boiler, per NFPA rules, using natural draft of the taller (700 ft.) stack. Due to the high pressure drop associated with the FGD stack, it cannot establish a natural draft to vent the boilers.
**On-Line Scrubber Maintenance**: Any time the plant conducts on-line Scrubber maintenance requiring the Scrubber to be bypassed, the bypass stack is used to vent flue gases.

**Scrubber Electric Power Interruption**: Any time the electric power is interrupted to the Scrubber requiring the Scrubber to be bypassed, the bypass stack is used to vent flue gases.

**COMPLIANCE ASSURANCE MONITORING**

CAM is intended to provide a reasonable assurance of compliance with applicable requirements under the Clean Air Act for large emission units that rely on air pollution control (APC) equipment to achieve compliance. The CAM approach establishes monitoring for the purpose of: (1) documenting continued operation of the control measures within ranges of specified indicators of performance (such as emissions, control device parameters, and process parameters) that are designed to provide a reasonable assurance of compliance with applicable requirements; (2) indicating any excursions from these ranges; and (3) responding to the data so that the cause or causes of the excursions are corrected. In order for a unit to be subject to CAM, the unit must be located at a major source, be subject to an emission limitation or standard; use a control device to achieve compliance; have post-control emissions of at least 100% of the major source amount (for initial CAM submittals); and must not otherwise be exempt from CAM. Applicability determinations are made on a pollutant-by-pollutant basis for each emission unit.

Pursuant to 40 CFR Part 64.2(b), the requirements of CAM do not apply to emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act and Acid Rain Program requirements. Units D-1, D-2 and D-3 boilers are subject to the requirement of 40 CFR Part 63 Subpart UUUUU (compliance date of April 16, 2015) which is a post 11/15/1990 NESHAP and the Acid Rain Program.

Dickerson Generating Station conducted a Compliance Assurance Monitoring (CAM) analysis for the facility and determined that only the particulate matter emissions from Units D-1, D-2 and D-3 boilers by-pass stack are subject to CAM requirements. The renewal application was submitted to the Department with a CAM analysis and a proposed CAM plan for particulate matter emissions (PM) from Units D-1, D-2 and D-3 boilers by-pass stack.

The MACT, Subpart UUUUU allows for use of continuous particulate emission monitoring system (PEMS) to demonstrate continuous compliance with a filterable PM limit. PEMS are required for the main stack as well as the bypass stack. PEMS were installed in the main stack in 2009. The PEMS data will be
used to demonstrate continuous compliance with the MATS PM limit and the SIP PM limit. Under subpart UUUUU, §63.10010(a) (4) if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, one may install a CEMS only on the main stack and count bypass hours as deviations from the monitoring requirements. The Dickerson Generating Station will not be able to certify and quality assure data from a PEMS on the bypass stack so NRG will be reporting deviations of the monitoring requirements of subpart UUUUU whenever the bypass stack is used.

**Potomac River Consent Decree**
GenOn entered into an Amended Consent Decree (“Potomac River Consent Decree”) with the State of Virginia, the State of Maryland and EPA Region III on 4/18/07. The Potomac River Consent Decree establishes a system-wide NO\textsubscript{X} emission cap on the Chalk Point (Maryland), Dickerson (Maryland), Morgantown (Maryland), and Potomac River (Virginia) electric generating stations. The Potomac River Consent Decree caps went into effect prior to the Healthy Air Act reductions of 2009. The reductions under the Potomac River Consent Order, in many cases, are now superseded by the more stringent requirements of the Healthy Air Act. The Potomac River Consent Decree states that “Within one hundred eighty (180) days after entry of this Consent Decree, GenOn shall apply for amendment of its Title V permits or applicable state operating permits for each plant in the GenOn System, and amend any existing Title V permit application, to include a schedule for all Unit-specific and system-wide performance, operational, maintenance and control technology requirements established by this Consent Decree including, but not limited to, the Unit-specific NO\textsubscript{X} emission control requirements set forth in Section IV, Subsections A (Potomac River Plant) and B (Morgantown Plant), the Unit-specific SO\textsubscript{2} and Mercury emission control requirements, as applicable, set forth in Section XVIII (Severing the Morgantown Plant or both the Morgantown and Dickerson Plants: Alternative Control Requirements), the System-Wide Ozone Season Emission Rate, System-Wide Annual Tonnage Limitations, System-Wide ozone Season Tonnage Limitations, and, as to the Potomac River Plant’s permits only, the Potomac River Annual and Ozone Season Tonnage Limitations, as set forth in this Consent Decree.”

*Please Note: Potomac River Station is no longer in operation, it shutdown in October 2012.*

**MARCH 2008 – Opacity CONSENT DEGREE**
In 2008, GenOn entered into a Consent Decree with the Department regarding violations of State air pollution laws and regulations at GenOn’s three electric generating stations including the Dickerson Generating Station. Requirements from this Consent Decree are discussed in the State-Only Section of the fact sheet and the Title V permit.
Please Note: Letter dated October 6, 2011 from MDE granting GenOn’s Petition to withdraw from the 170-day particulate matter stack testing requirements of the March 6, 2008 Opacity Consent Decree since the PM CEMs have been reliably operating for a period of at least one year and generating particulate matter emissions data that is deemed accurate by the Department. Effective October 1, 2011, GenOn ceased performing the 170-day particulate matter stack tests on the Morgantown, Dickerson and Chalk Point Generating Stations and began performing annual particulate matter stack tests in 2012. GenOn shall continue to operate and maintain all four PM CEMs on the three generating stations.

HEALTHY AIR ACT
Under the Healthy Air Act, which was signed into law on April 6, 2006, GenOn is required to cap emissions of coal-fired units including the coal fired units (Units D-1, D-2 and D-3) at Dickerson Generating Station. The NOX reductions under the Healthy Air Act occurred in two phases, 2009 and 2012. GenOn installed pollution control equipment at Dickerson Generating Station in order to comply with Healthy Air Act requirements by reducing NOX, SO2 and mercury emissions.

On July 19, 2007, GenOn was issued a Certificate of Public Convenience and Necessity (CPCN) from the Public Service Commission (Case #9087) for the installation of a flue gas desulfurization (FGD) system and associated equipment to control sulfur dioxide (SO2) and mercury air emissions. Construction of the FGD system started on January 8, 2008.

Regional Greenhouse Gas Initiative
The Regional Greenhouse Gas Initiative (RGGI) is a market-based carbon dioxide (CO2) cap and trade program designed to reduce CO2 emissions from fossil fuel-fired power plants. It is a Maryland State-only enforceable program. The Healthy Air Act (discussed above) required Maryland to join RGGI by July 2007. Maryland joined RGGI by signing RGGI’s multi-state Memorandum of Understanding (MOU) on April 20, 2007. The MOU requires Maryland to adopt regulations by December 31, 2008, implementing the RGGI program. The Maryland CO2 Budget Trading Program, Code of Maryland Regulations (COMAR) 26.09.01 to .03, became effective on July 17, 2008. COMAR 26.09.04 became effective as an emergency action on April 4, 2008 and as a permanent action on August 25, 2008.

The regulations require the following:
1) Implement a cap and trade program for CO2 emissions from fossil fuel-fired electric generating units located in Maryland having a capacity of at least 25 megawatts;
2) Distribute CO2 allowances to stakeholders through auction, sale and/or allocation;
3) Require each affected source to have a CO\textsubscript{2} budget account representative and a compliance account;
4) Require each budget unit to hold in its source’s compliance account at the end of each 3-year control period one allowance for each ton of CO\textsubscript{2} emissions emitted in that period;
5) Require sources to monitor emissions and submit quarterly and annual emission reports;
6) Establish set-aside accounts for voluntary renewable purchase, limited industrial generator exemptions, and long-term contract generators;
7) Establish a consumer benefit or strategic energy purpose fund to support energy efficiency, directly mitigate electricity ratepayer impacts, promote renewable or non-carbon emitting energy technologies, stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and fund administration of the program; and
8) Establish procedures to evaluate and award allowances to persons who undertake offset projects that will reduce CO\textsubscript{2} emissions.
9) Require affected sources to submit an application for a CO\textsubscript{2} Budget Permit. A CO\textsubscript{2} Budget Permit when issued will be an attachment to the Part 70 permit.

GREENHOUSE GAS (GHG) EMISSIONS
Dickerson Generating Station emits the following greenhouse gases (GHGs) related to Clean Air Act requirements: carbon dioxide, methane, and nitrous oxide. These GHGs originate from various processes (i.e. boilers, combustion turbines) contained within the facility premises applicable to Dickerson Generating Station. The facility has not triggered Prevention of Significant Deterioration (PSD) requirements for GHG emissions; therefore, there are no applicable GHG Clean Air Act requirements. While there may be no applicable requirements as a result of PSD, emission certifications reports for the years 2009, 2010, and 2011, showed that Dickerson Generating Station is a major source (threshold: 100,000tpy CO\textsubscript{2}e) for GHG’s (see Table shown below). The Permittee shall quantify facility wide GHGs emissions and report them in accordance with Section 3 of the Part 70 permit.

The following table summarizes the actual emissions from Dickerson Generating Station based on its Annual Emission Certification Reports:
Table: Greenhouse Gases Emissions Summary

<table>
<thead>
<tr>
<th>GHG</th>
<th>Conversion factor</th>
<th>2014 tpy CO₂e</th>
<th>2013 tpy CO₂e</th>
<th>2012 tpy CO₂e</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon dioxide CO₂</td>
<td>1</td>
<td>1,232,445</td>
<td>2,353,474.30</td>
<td>1,301,747</td>
</tr>
<tr>
<td>Methane CH₄</td>
<td>25</td>
<td>20.37</td>
<td>8.81</td>
<td>12.14</td>
</tr>
<tr>
<td>Nitrous Oxide N₂O</td>
<td>298</td>
<td>139.69</td>
<td>16.60</td>
<td>19.38</td>
</tr>
<tr>
<td>Total GHG CO₂eq</td>
<td></td>
<td>1,242,009</td>
<td>2,353,499</td>
<td>1,301,778</td>
</tr>
</tbody>
</table>

**MERCURY AND AIR TOXICS (MATS) RULE**

The US EPA finalized on February 16, 2012, the National Emissions Standards for Hazardous Air Pollutants from coal and oil-fired Electric Utility Steam Generating Units (EGUs) codified under 40 CFR Part 63, Subpart UUUU, also known as the Mercury and Air Toxics (MATS) rule. The MATS rule established national emission limitations and work practices for certain hazardous air pollutants emitted from coal and oils-fired steam generating units as well as requirements to demonstrate initial and continuous compliance with the emission limitations. Existing units are required to comply with the rule requirements by April 16, 2015 while new or reconstructed units were required to comply by April 16, 2012 or upon start-up.

Dickerson Generating Station is subject to the requirements of this rule because it meets the applicability requirements for the rule as an existing source. A source is subject to the rule if it is a coal-fired EGU or oil-fired EGU as defined in §63.10042. The section defined a coal-fired electric utility steam generating unit as an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year. The section also defined electric utility steam generating unit (EGU) as a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. It further adds that a fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. Coal-fired EGUs are subcategorized as defined in §63.10042 and as:

1. EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and
2. EGUs designed for low rank virgin coal (Ref: §63.9990).
Dickerson Generating Station falls under the EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb. Specific limitations and requirements, which Dickerson Generating Station must meet are presented below and in the permit.

The MATS rule will reduce emissions of heavy metals including mercury (Hg), arsenic (As), chromium (Cr), nickel (Ni) and acid gases including hydrochloric acid (HCl) and Hydrofluoric acid (HF). In the rule particulate matter (PM) is a surrogate for toxic non-mercury metals and HCl is a surrogate for toxic acid gases. Sulfur dioxide (SO\textsubscript{2}) may also be a surrogate for HCl if the EGU has a flue gas desulfurization (FGD) system. Dickerson’s three (3) EGUs have CEM system continuously monitoring emissions from the scrubber stack including PM, SO\textsubscript{2} and Hg. CEM data will be used to demonstrate compliance with the MATS standard by calculation the 30-boiler operating day arithmetic average. Dickerson must begin and continue collecting PM, SO\textsubscript{2} and Hg data by September 9, 2015. The rule also requires the Dickerson EGU to startup and shutdown utilizing clean fuels. These units use ultra low sulfur diesel fuel during these operations. The rule also requires periodic tune-ups of the Dickerson EGUs burners and combustion controls.

**EMISSION UNIT IDENTIFICATION**

Dickerson Generating Station has identified the following emission units as being subject to Title V permitting requirements and having applicable requirements.

**Table 2: Emission Unit Identification**

<table>
<thead>
<tr>
<th>Emissions Unit Number</th>
<th>MDE Registration Number</th>
<th>Emissions Unit Name and Description</th>
<th>Date of Installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>D-1</td>
<td>3-0001</td>
<td>One (1) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boiler nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boiler unit is equipped with LNBs and Separated Over-fired air (SOFA), a SNCR system, an ESP, a common baghouse and a common FGD system.</td>
<td>June 1959</td>
</tr>
<tr>
<td>D-2</td>
<td>3-0002</td>
<td>One (1) Combustion Engineering, Inc tangentially fired, dry bottom, drum,</td>
<td>April 1960</td>
</tr>
<tr>
<td>Emissions Unit Number</td>
<td>MDE Registration Number</td>
<td>Emissions Unit Name and Description</td>
<td>Date of Installation</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>bituminous coal fired boiler nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boiler unit is equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system.</td>
<td></td>
</tr>
<tr>
<td>D-3</td>
<td>3-0003</td>
<td>One (1) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boiler nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boiler unit is equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system.</td>
<td>March 1962</td>
</tr>
<tr>
<td>D CT-1</td>
<td>4-0907</td>
<td>One (1) Pratt and Whitney FT4-A combustion turbine rated at 18 megawatts, fires No.2 fuel oil and utilized for black start and peaking service.</td>
<td>March 1967</td>
</tr>
<tr>
<td>H CT-1</td>
<td>9-0362</td>
<td>One (1) General Electric Frame 7F combustion turbine with a nominal rated capacity of 167 megawatts located at Station H. The combustion turbine fires primarily natural gas and No. 2 fuel oil as a secondary fuel. The unit is equipped with inlet foggers to maintain output at high ambient temperatures and with water injection to control NO\textsubscript{X} emissions.</td>
<td>June 1992</td>
</tr>
<tr>
<td>H CT-2</td>
<td>9-0363</td>
<td>One (1) General Electric Frame 7F combustion turbine with a nominal rated capacity of 167 megawatts located at Station H. The combustion turbine fires primarily natural gas and No. 2 fuel oil as a secondary fuel. The unit is equipped with inlet foggers to maintain output at high ambient temperatures and with water injection to control NO\textsubscript{X} emissions.</td>
<td>June 1993</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Ash and coal handling operations</td>
<td></td>
</tr>
</tbody>
</table>
### Emissions Units

<table>
<thead>
<tr>
<th>Emissions Unit Number</th>
<th>MDE Registration Number</th>
<th>Emissions Unit Name and Description</th>
<th>Date of Installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>FGD System</td>
<td>CPCN 9087</td>
<td>A common wet flue gas desulfurization (FGD) system is installed on Units 1-3. The FGD system controls SO$_2$ and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing gypsum as a by-product. The FGD system consists of the following sub-systems: limestone unloading and storage facilities; limestone slurry preparation and feed; SO$_2$ absorption tower; gypsum dewatering and loading facilities and two emergency diesel engines.</td>
<td>December 2009</td>
</tr>
<tr>
<td>SNCR System</td>
<td>CPCN 9140</td>
<td>Unit 1-3 have Selective Non-Catalytic Reduction systems installed, consisting of urea injectors on the boilers and associated ancillary equipment</td>
<td>May 2009</td>
</tr>
</tbody>
</table>

### AN OVERVIEW OF THE PART 70 PERMIT

The Fact Sheet is an informational document. If there are any discrepancies between the Fact Sheet and the Part 70 permit, the Part 70 permit is the enforceable document.

Section I of the Part 70 Permit contains a brief description of the facility and an inventory list of the emissions units for which applicable requirements are identified in Section IV of the permit.

Section II of the Part 70 Permit contains the general requirements that relate to administrative permit actions. This section includes the procedures for renewing, amending, reopening, and transferring permits, the relationship to permits to construct and approvals, and the general duty to provide information and to comply with all applicable requirements.

Section III of the Part 70 Permit contains the general requirements for testing, record keeping and reporting; and requirements that affect the facility as a whole, such as open burning, air pollution episodes, particulate matter from construction and demolition activities, asbestos provisions, ozone depleting substance provisions, general conformity, and acid rain permit. This section includes the requirement to report excess emissions and deviations, to submit an annual
emissions certification report and an annual compliance certification report, and results of sampling and testing.

Section IV of the Part 70 Permit identifies the emissions standards, emissions limitations, operational limitations, and work practices applicable to each emissions unit located at the facility. For each standard, limitation, and work practice, the permit identifies the basis upon which the Permittee will demonstrate compliance. The basis will include testing, monitoring, record keeping, and reporting requirements. The demonstration may include one or more of these methods.

Section V of the Part 70 Permit contains a list of insignificant activities. These activities emit very small quantities of regulated air pollutants and do not require a permit to construct or registration with the Department. For insignificant activities that are subject to a requirement under the Clean Air Act, the requirement is listed under the activity.

Section VI of the Part 70 Permit contains State-only enforceable requirements. Section VI identifies requirements that are not based on the Clean Air Act, but solely on Maryland air pollution regulations. These requirements generally relate to the prevention of nuisances and implementation of Maryland's Air Toxics Program.

**REGULATORY REVIEW/TECHNICAL REVIEW/COMPLIANCE METHODOLOGY**

**Emissions Unit Number(s) D-1, D-2 & D-3: Boilers**

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003) In 1999, low NOx burners (LNBs) were installed on all three (3) coal fired boilers. By the end of 2002, Separated Over-fired Air (SOFA) was installed on the three (3) coal fired boilers.

These boilers are not subject to requirements of 40 CFR Part 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units since these boilers commenced constructed prior to September 18, 1978.

These boilers are subject to the requirements of 40 CFR Part 63 Subpart UUUUUU-National Emission Standards for Hazardous Air Pollutants: Coal- and
Oil-Fired Electric Utility Steam Generating Units (D-1, D-2 and D-3). See Table IV-1e.

PEMS, NO\textsubscript{X} & SO\textsubscript{2} CEM reports are submitted quarterly.

**Applicable Standards and Limitations:**

**A. Control of Visible Emissions**

**COMAR 26.11.09.05A(2) – Fuel Burning Equipment**

“Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity.”

**COMAR 26.11.09.05A(3) - Exceptions.** “Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period.”

**Compliance Demonstration**

**For The Bypass Stack:**

The Permittee, in accordance with COMAR 26.11.01.10B, shall continuously monitor opacity of the stack gases using a continuous opacity monitor that is certified in accordance with 40 CFR Part 60, Appendix B and meets the quality assurance criteria of COMAR 26.11.31. [Reference: COMAR 26.11.01.10C]

The Permittee shall maintain all records necessary to comply with the data reporting requirements by COMAR 26.11.01.11E(2) on file. [Reference COMAR 26.11.01.11E] The Permittee shall perform quality assurance procedures on the continuous opacity monitoring system as established in COMAR 26.11.31. [Reference: COMAR 26.11.03.06C]

The Permittee shall report:

All CEM system downtime that lasts or is expected to last more than 24 hours shall be reported to the Department by telephone before 10 a.m. of the first regular business day following the breakdown.

The system breakdown report required by Sec. E(1)(a) of this regulation shall include the reason, if known, for the breakdown and the estimated period of time that the CEM will be down. The owner or operator of the CEM shall notify the Department by telephone when an out-of-service CEM is back in operation and producing valid data. [Reference: COMAR 26.11.01.11E(1)]

The Permittee shall submit:
Quarterly summary reports to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:

(i) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards;
(ii) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;
(iii) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;
(iv) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;
(v) Quarterly quality assurance activities; and
(vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and
(vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation.” [Reference: COMAR 26.11.01.11E(2)]

For the Scrubber Stack (the main stack): The Permittee shall use the data from the PEMS to demonstrate compliance with the opacity standard. If the PEMS shows compliance with the PM limits, compliance with the opacity standard is assured. The opacity limit was established based on correlation to the PM limit of 0.03 gr/dscf. The scrubber emits a wet plume so an accurate opacity measurement cannot be performed.

B. Control of Particulate Matter Emissions

COMAR 26.11.09.06B(3) – Solid Fuel Burning Equipment. “A person may not cause or permit particulate matter caused by the combustion of solid fuel to be discharged into the atmosphere in excess of the amounts shown in Table 1.” For these units, the maximum allowable emissions of particulate matter 0.03 gr/scfd @ 50% excess air.

COMAR 26.11.09.06C. Determination of Compliance. “Compliance with the particulate matter emissions standards in this regulation shall be calculated as the average of 3 test runs using EPA Test Method 5 or other United States Environmental Protection Agency test method approved by the Department.”
MATS Rule 40 CFR Part 63, Subpart UUUUU – The MATS filterable PM limit is 0.03 lbs/mmBTU or 0.3 lbs/MWh. See the discussion of the MATS rule for the compliance demonstration.

Compliance Demonstration

For the bypass Stack: The Permittee shall comply with the CAM plan. Details of the plan are described beginning on Page 32 of this Fact Sheet.

For the Scrubber Stack (the main stack): The Permittee in accordance with COMAR 26.11.01.04A(1) and July 22, 1992 Consent Order, shall conduct annual testing. Annual testing shall be performed using EPA Reference Method 5 of 40 CFR Part 60 Appendix A (Section C). The Permittee shall submit a protocol to the Department for approval at least 30 days prior to the scheduled date of the test. [Reference: COMAR 26.11.03.06C]

The Permittee shall perform fuel sampling as follows: (1) Fuel sampling for solid fuel-fired units – one grab sample be taken as-bunkered or as-fired during each test run with the results of a proximate analysis for each sample included with the test report. Reported parameters shall include volatile matter, carbon, ash and sulfur contents and heating value in Btu/lb. [Reference: July 22, 1992 Consent Decree, Condition 1C- COMAR 26.11.03.06C].

The Permittee shall operate and maintain a particulate emissions monitoring system (PEMS). [Reference: COMAR 26.11.03.06C]. Note: The MATS Rule also requires PEMS

The Permittee shall maintain records of all particulate matter emissions tests. [Reference: COMAR 26.11.03.06C]

The Permittee shall submit a test protocol/notification to the Department at least 30 days prior to test and notify the Department at least 10 days prior to testing. The Permittee shall report the results of the particulate emissions stack test to the Department within 45 days after completion of the testing. [Reference: COMAR 26.11.03.06C]

The Permittee shall submit quarterly PEMS reports to the Department that comply with COMAR 26.11.01.11E(2)(c). The emissions shall be reported on an one hour average in units of grains per dry standard cubic feet.

The Permittee shall submit: Quarterly summary reports to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:
(i) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards;
(ii) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;
(iii) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;
(iv) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;
(v) Quarterly quality assurance activities; and
(vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and
(vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation.” [Reference: COMAR 26.11.01.11E(2)]

Discussion of compliance rationale: The average one hour PEMS data will allow the Department to assess compliance with the 0.03 gr/dscf. Upon operation of the FGD scrubber in 2010, the hourly average PM emissions reported in the quarterly PEMS reports have ranged from 0.002 to 0.003 gr/dscf which is an order of magnitude less than the limit. This includes periods of boiler startup and shutdown.

C. Control of Sulfur Oxides
   (1) SIP Revision - Sulfur emissions of solid fuel is limited to 2.8 lb. per million Btu averaged over a 24-hour period.
   A review process to include emissions and ambient air quality levels in the vicinity of the plant shall be repeated by both parties in five year intervals beginning in the year 1985 and continuing thereafter. If at any time the Department determines that any applicable ambient air quality standard for sulfur oxides or any other compound if sulfur is likely to be exceeded, the Department shall notify the Permittee of such determination and the Permittee shall submit a timetable to purchase and use of complying fuel and achieve compliance within one (1) year after notification.
   [Reference: §52.1070(d) EPA approved source-specific requirements. Potomac Electric Power Company (PEPCO) – Dickerson, #49352 Amended Consent Order, state effective 7/26/78]
Compliance Demonstration
For 1) through 4):
The Permittee shall continuously monitor sulfur dioxide emissions using a CEM that meet the requirements of 40 CFR Part 75, Subpart B §75.10A(1) & (2). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with SO₂ standard, the Health Air Act limitations, Potomac River Consent Decree, the Acid Rain Program, and the Clean Air Interstate Rule. [Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, Potomac Consent Decree, July 22, 1992 Consent Decree, Acid Rain Permit, and CAIR Permit].
The Permittee shall perform quality control/quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. [Reference: COMAR 26.11.01.11C]
The Permittee shall maintain all records necessary to comply with data reporting requirements of COMAR 26.11.01.10G (2). [Reference COMAR 26.11.01.10G (2)].

(1) The Permittee shall submit annual fuel usage reports to the Department for all fuel-burning equipment and combustion turbines owned and/or operated by the Permittee in the State of Maryland. The annual report shall contain the type and quantity of each fuel used, the average sulfur content, average heating value of each fuel, and the number of hours and the approximate number of days the equipment operated. The annual report shall also contain the annual capacity factor for each of the electric generating unit. The annual fuel usage report shall be submitted no later than 60 calendar days following each calendar year. [Reference: July 22, 1992 Consent Decree, Condition 6]

The Permittee shall a quarterly summary report to the Department not later than 30 days following each calendar quarter that contains the information listed in COMAR 26.11.01.11E(2). [Reference: COMAR 26.11.01.11E].

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>Annual SO₂ Tonnage Limitations Beginning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson Unit 1</td>
<td>1,238 tons</td>
</tr>
<tr>
<td>Dickerson Unit 2</td>
<td>1,355 tons</td>
</tr>
<tr>
<td>Dickerson Unit 3</td>
<td>1,285 tons</td>
</tr>
<tr>
<td>System-wide</td>
<td>18,541 tons</td>
</tr>
</tbody>
</table>

(2) Emission Limitation for Power Plants requirements:
COMAR 26.11.27.03C. SO₂ Emission Limitations.
(1) Except as provided in §E of this regulation, annual SO₂ emissions from each affected electric generating unit may not exceed the number of tons in §C(2) of this regulation.
(2) Annual Tonnage Limitations.
COMAR 26.11.27.03E. System-Wide Compliance Determinations.
(1) Compliance with the emission limitations in §§B and C of this regulation may be achieved by demonstrating that the total number of tons emitted from all electric generating units in a system does not exceed the sum of the tonnage limitations for all electric generating units in that system.
(2) A system-wide compliance determination shall be based only upon emissions from units in Maryland that are subject to the emission limitations in §§B and C of this regulation.
(3) If a unit that is part of a system is transferred to a different person that does not own, operate, lease, or control an affected unit subject to this chapter, the transferred unit shall meet the limitations in §§B and C of this regulation applicable to that electric generating unit.

Compliance Demonstration
The Permittee shall maintain records sufficient to demonstrate compliance with the requirements of the Healthy Air Act, COMAR 26.11.27. [Reference: COMAR 26.11.01.05A].

COMAR 26.11.27.05 - Monitoring and Reporting Requirements.
B. Beginning with calendar year 2007 and each year thereafter, the owner or operator of each electric generating unit subject to this chapter shall submit an annual report to the Department, the Department of Natural Resources, and the Public Service Commission. The report for each calendar year shall be submitted not later than March 1 of the following year.
C. Each report shall include:
(1) Emissions performance results related to compliance with the emission requirements under this chapter;
(2) Emissions of NO\textsubscript{X} and SO\textsubscript{2}, and beginning with calendar year 2010, mercury, emitted during the previous calendar year from each affected unit;
(3) A current compliance plan; and
(4) Any other information requested by the Department.

(3) Acid Rain Permit
The Permittee shall comply with the requirements of the Phase II Acid Rain Permit issued for this generating station. Note: A renewal Phase II Acid Rain Permit will be issued in conjunction with this Part 70 permit and is attached to the Part 70 permit as Appendix A.

Compliance Demonstration
The Acid Rain Permit contains program specific recordkeeping and reporting requirements. [Reference: 40 CFR Part 75, Subpart F & Subpart G].
(4) Cross-State Air Pollution Rule
TR SO₂ Group 1 - Trading Program 40 CFR Part 97 Subpart CCCC

The Permittee shall comply with the provisions and requirements of §97.601 through §97.635.

Note: §97.606(c) SO₂ emissions requirements. For TR SO₂ Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all TR SO₂ Group 1 units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO₂ Group 1 allowance transfer must be submitted for recordation in a TR SO₂ Group 1 source's compliance account in order to be available for use in complying with the source's TR SO₂ Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624.

Compliance Demonstration
The Permittee shall comply with the monitoring, recordkeeping and reporting requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633.

D. Control of Nitrogen Oxides
(1) NOₓ RACT Requirements
COMAR 26.11.09.08B(5) - Operator Training.
(a) For purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation.
(b) The operator training course sponsored by the Department shall include an in-house training course that is approved by the Department.”

COMAR 26.11.09.08C. - Requirements for Fuel-Burning Equipment with a Rated Heat Input Capacity of 250 Million Btu Per Hour or Greater.
“(1) A person who owns or operates fuel-burning equipment with a rated heat input capacity of 250 Million Btu per hour or greater shall equip each installation with combustion modifications or other technologies to meet the NOₓ emission rates in §C(2) of this regulation.
(2) The maximum NOₓ emission rates as pounds of NOₓ per Million Btu per hour are:
(a) 0.45 for tangentially coal fired units located at an electric generating facility (excluding high heat release units);
(b) 0.50 for wall coal fired units located at an electric generating facility (excluding high heat release units);
(c) 0.30 for oil fired or gas/oil fired units located at an electric generating facility;
(d) 0.70 for coal fired cyclone fuel burning equipment located at an electric generating facility from May 1 through September 30 of each year and 1.5 during the period October 1 through April 30 of each year;
(e) 0.70 for a tangentially coal fired high heat release unit located at an electric generating facility;
(f) 0.80 for a wall coal fired high heat release unit located at an electric generating facility;
(g) 0.6 for coal fired cell burners at an electric generating facility; and
(h) 0.70 for fuel burning equipment stacks at a non-electric generating facility during the period May 1 through September 30 of each year and 0.99 during the period October 1 through April 30 of each year.
(3) A person who owns or operates fuel burning equipment with a rated heat input capacity of 250 Million Btu per hour or greater shall install, operate, calibrate, and maintain a certified NO\textsubscript{X} CEM or an alternative NO\textsubscript{X} monitoring method approved by the Department and the EPA on each installation.

**COMAR 26.11.09.08B(2)(d)** - Demonstration of Compliance. “Except as otherwise established by the Department and approved by the EPA, for a person who establishes compliance with the NO\textsubscript{X} emissions standards in this regulation using a CEM, compliance shall be determined as 30-day rolling averages.”

**Compliance Demonstration**
For 1) through 5):
The Permittee shall continuously monitor NO\textsubscript{X} emissions that meet the requirements of 40 CFR Part 75, Subpart B §75.10A(2). This continuous monitoring system shall be used to collect emissions information to demonstrate the SIP NO\textsubscript{X} standard, the Healthy Air Act limitations, the Potomac River Consent Decree, the Acid Rain Program, and the Clean Air Interstate Rule.

[Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, Potomac Consent Decree, July 22, 1992 Consent Decree, Acid Rain Permit, and CAIR Permit].
The Permittee shall perform quality control/quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. [Reference: COMAR 26.11.01.11C]
The Permittee shall certify CEMs in accordance with 40 CFR Part 75, Appendix A. [Reference: COMAR 26.11.09.08B(2)(b)]
The Permittee shall maintain records necessary for the quarterly emission reports. [Reference: COMAR 26.11.03.06C]
The Permittee shall submit quarterly emission reports of CEM data to the Department on or before the thirtieth day of the month following the end of each calendar quarter. The emissions report shall contain the information required by COMAR 26.11.01.10G (2). [Reference: COMAR 26.11.09.08K(1) and COMAR 26.11.03.06C]
(2) Emission Limitation for Power Plants requirements:

**COMAR 26.11.27.03B. NO\textsubscript{X} Emission Limitations.**

“(1) Except as provided in §E of this regulation, annual NO\textsubscript{X} emissions from each affected electric generating unit may not exceed the number of tons in §B(2) of this regulation.

(2) Annual Tonnage Limitations.

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>Annual NO\textsubscript{X} Tonnage Limitations Beginning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson Unit 1</td>
<td>554 tons</td>
</tr>
<tr>
<td>Dickerson Unit 2</td>
<td>607 tons</td>
</tr>
<tr>
<td>Dickerson Unit 3</td>
<td>575 tons</td>
</tr>
<tr>
<td>System-wide</td>
<td>8,298 tons</td>
</tr>
</tbody>
</table>

(3) Except as provided in §E of this regulation, ozone season NO\textsubscript{X} emissions from each affected electric generating unit may not exceed the number of tons in §B(4) of this regulation.”

“(6) Ozone Season Tonnage Limitations.

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>Ozone Season NO\textsubscript{X} Tonnage Limitations Beginning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson Unit 1</td>
<td>257 tons</td>
</tr>
<tr>
<td>Dickerson Unit 2</td>
<td>274 tons</td>
</tr>
<tr>
<td>Dickerson Unit 3</td>
<td>259 tons</td>
</tr>
<tr>
<td>System-wide</td>
<td>3,567 tons</td>
</tr>
</tbody>
</table>

(7) Electric System Reliability During Ozone Seasons.

(a) An exceedance of the NO\textsubscript{X} limitations in §B(4) or (6) of this regulation which occurs because PJM Interconnection, LLC or a successor independent system operator, acts to invoke "Maximum Emergency Generation", "Load Reduction", "Voltage Reduction", "Curtailment of Non-essential Building Load", or "Manual Load Dump" procedures in accordance with the current PJM Manual, or a PJM alert preceding such action as to a generating unit that has temporarily shut down in order to avoid potential interruption in electric service and maintain electric system reliability is not a violation of this chapter provided that:

(i) Within 36 hours following the action, the owner or operator of the affected electric generating unit or units notifies the Manager of the Air Quality Compliance Program of the action taken by PJM Interconnection and provides the Department with documentation of the action which is satisfactory to the Department;

(ii) Within 48 hours after completion of the action, the owner or operator of the affected unit or units provides the Department with the estimated NO\textsubscript{X} emissions in excess of the emission limitation; and

(iii) See State-only enforceable section of the permit for additional requirement.
(b) The owner or operator of an electric generating unit or system, as applicable, shall send written notice to the Manager of the Air Quality Compliance Program not later than 5 business days following the day when the cumulative ozone season NO\textsubscript{X} emissions of an electric generating unit or system, as applicable, are:
(i) Equal to approximately 80 percent of the applicable ozone season emission limitation; and
(ii) Equal to the applicable ozone season emission limitation. “

**COMAR 26.11.27.03E. System-Wide Compliance Determinations.**
“(1) Compliance with the emission limitations in §§B and C of this regulation may be achieved by demonstrating that the total number of tons emitted from all electric generating units in a system does not exceed the sum of the tonnage limitations for all electric generating units in that system.
(2) A system-wide compliance determination shall be based only upon emissions from units in Maryland that are subject to the emission limitations in §§B and C of this regulation.
(3) If a unit that is part of a system is transferred to a different person that does not own, operate, lease, or control an affected unit subject to this chapter, the transferred unit shall meet the limitations in §§B and C of this regulation applicable to that electric generating unit.”

**Compliance Demonstration**
The Permittee shall maintain records sufficient to demonstrate compliance with the requirements of the Healthy Air Act, COMAR 26.11.27. [Reference: COMAR 26.11.01.05A].

**COMAR 26.11.27.05 - Monitoring and Reporting Requirements.**
**B.** Beginning with calendar year 2007 and each year thereafter, the owner or operator of each electric generating unit subject to this chapter shall submit an annual report to the Department, the Department of Natural Resources, and the Public Service Commission. The report for each calendar year shall be submitted not later than March 1 of the following year.

**C.** Each report shall include:
(1) Emissions performance results related to compliance with the emission requirements under this chapter;
(2) Emissions of NO\textsubscript{X} and SO\textsubscript{2}, and beginning with calendar year 2010, mercury, emitted during the previous calendar year from each affected unit;
(3) A current compliance plan; and
(4) Any other information requested by the Department.

(3) Potomac River Consent Decree
The Permittee shall comply with the requirements of Potomac River Consent Decree. See Table IV- 1a
Note: The Consent Decree establishes a GenOn System-Wide Annual NO\textsubscript{X} Tonnage Limitation and a System-Wide Ozone Season NO\textsubscript{X} Emissions Limitation. Dickerson Units 1, 2 and 3 are included in the GenOn System. See the details of the Potomac River Consent Decree in the Fact Sheet for Emission Units D-1 thru D-3.

Compliance Demonstration
The Permittee shall comply with the recordkeeping requirements of the Potomac River Consent Decree. See paragraph 17 in Table IV-1a: Potomac River Consent Decree. [Reference: COMAR 26.11.03.06C]
The Permittee shall comply with the reporting requirements of the Potomac River Consent Decree. See paragraphs 15 and 18 through 23 in Table IV-1a: Potomac River Consent Decree. [Reference: COMAR 26.11.03.06C]

(4) Acid Rain Permit
The Permittee shall comply with the requirements of the renewal Phase II Acid Rain Permit issued for this generating station. Note: A renewal Phase II Acid Rain Permit will be issued in conjunction with this Part 70 permit and is attached to the Part 70 permit as Appendix A.

Compliance Demonstration
The Acid Rain Permit contains program specific recordkeeping and reporting requirements. [Reference: 40 CFR Part 75, Subpart F & Subpart G].

(5) Cross-State Air Pollution Rule
**TR NO\textsubscript{X} Annual Trading Program 40 CFR Part 97 Subpart AAAAA**
The Permittee shall comply with the provisions and requirements of §97.401 through §97.435.

**Note: §97.406(c) NO\textsubscript{X} emissions requirements.** For TR NO\textsubscript{X} Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\textsubscript{X} Annual source and each TR NO\textsubscript{X} Annual unit at the source shall hold, in the source's compliance account, TR NO\textsubscript{X} Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NO\textsubscript{X} emissions for such control period from all TR NO\textsubscript{X} Annual units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\textsubscript{X} Annual allowance transfer must be submitted for recordation in a TR NO\textsubscript{X} Annual source’s compliance account in order to be available for use in complying with the source’s TR NO\textsubscript{X} Annual emissions limitation for such control period in accordance with §§97.406 and 97.424.
TR NO\textsubscript{X} Ozone Season Trading Program 40 CFR Part 97 Subpart BBBBB

The Permittee shall comply with the provisions and requirements of §97.501 through §97.535.

**Note: §97.506(c) NO\textsubscript{X} emissions requirements.** For TR NO\textsubscript{X} Ozone Season emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\textsubscript{X} Ozone Season source and each TR NO\textsubscript{X} Ozone Season unit at the source shall hold, in the source’s compliance account, TR NO\textsubscript{X} Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NO\textsubscript{X} emissions for such control period from all TR NO\textsubscript{X} Ozone Season units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\textsubscript{X} Ozone Season allowance transfer must be submitted for recordation in a TR NO\textsubscript{X} Ozone Season source’s compliance account in order to be available for use in complying with the source’s TR NO\textsubscript{X} Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524.

**Compliance Demonstration**

The Permittee shall comply with the monitoring, recordkeeping and reporting requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the NO\textsubscript{X} Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NO\textsubscript{X} Ozone Season Trading Program.

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**Emissions Unit Number(s):** D-1, D-2 & D-3: Boilers Cont’d

**Potomac River Consent Decree**

**Applicable Standards and Limitations:**

**Control of Nitrogen Oxides**

**System-wide Annual Tonnage Limitations for NO\textsubscript{X}**

1. Except as provided in Paragraph 185, 188, or 189 as applicable, GenOn shall comply with the following System-Wide Annual Tonnage Limitations for NO\textsubscript{X}, which apply to all Units collectively within the GenOn System, during each year specified in Table A below:

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 57.]

**Note:** The GenOn system consists of Chalk Point Generating Station Unit 1 and Unit 2; Dickerson Generating Station Unit 1, Unit 2, and Unit 3; Morgantown Generating Station Unit 1 and Unit 2; and Potomac River Generating Station Unit
Paragraph 185, 188, and 189 refer to revised requirements that are triggered if GenOn severs the Morgantown Station, the Dickerson Station, or both the Morgantown and Dickerson Stations from the GenOn System.

Table A

<table>
<thead>
<tr>
<th>Applicable Year</th>
<th>System-Wide Annual Tonnage Limitations for NO\textsubscript{X}</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 and each year after</td>
<td>16,000 tons</td>
</tr>
</tbody>
</table>

2. Except as provided in Paragraph 185,188, or 189 as applicable, beginning May 1, 2004, for each Ozone Season specified, the sum of the tons by all Units within the GenOn System, shall not exceed the following System-Wide Ozone Season Tonnage Limitations for NO\textsubscript{X} in Table B below:

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 58.]

Note: The GenOn system consists of Chalk Point Generating Station Unit 1 and Unit 2; Dickerson Generating Station Unit 1, Unit 2, and Unit 3; Morgantown Generating Station Unit 1 and Unit 2; and Potomac River Generating Station Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5. (Potomac River shut down in October 2012). Paragraph 185, 188, and 189 refer to revised requirements that are triggered if GenOn severs the Morgantown Station, the Dickerson Station, or both the Morgantown and Dickerson Stations from the GenOn System.

Table B

<table>
<thead>
<tr>
<th>Applicable Ozone Season</th>
<th>System-Wide Ozone Season Tonnage Limitations for NO\textsubscript{X}</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 and each ozone season thereafter</td>
<td>5,200 tons</td>
</tr>
</tbody>
</table>

3. Except as provided in Paragraph 185,188, or 189 as applicable, beginning May 1, 2008, and continuing for each and every Ozone Season thereafter, the GenOn System, shall not exceed a System-Wide Ozone Season Emissions Rate of 0.150 lb/mm Btu NO\textsubscript{X}.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 59.]

4. If GenOn exceed the limitations specified in Section IV, Subsection C (System-Wide Annual Tonnage Limitations for NO\textsubscript{X}) or D (System-Wide Ozone Season Emissions Limitations), GenOn may not claim compliance with this Decree by using, tendering, or otherwise applying NO\textsubscript{X} Allowances that were obtained prior to lodging of this Decree, or that are subsequently purchased or otherwise obtained, and stipulated penalties apply as set forth in Section XI (Stipulated Penalties). Except as provided in Paragraphs 61 and 66, NO\textsubscript{X} Allowances allocated to, or purchased by, or on behalf of, the GenOn System
may not be used by GenOn to meet its own federal and/or State Clean Air Act regulatory requirements to the extent otherwise allowed by law.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 60.]

5. Solely for the purpose of compliance with any present or future NO\textsubscript{X} trading program set forth in the Maryland State Implementation Plan including, the Maryland NO\textsubscript{X} Reduction and Trading Program, COMAR 26.11.29-26.11.30, beginning with:
   (a) the 2004 Ozone Season and during each Ozone Season thereafter, and
   (b) the year that an annual NO\textsubscript{X} allowance trading program becomes effective in Maryland, and during each year thereafter, GenOn must first use: (1) any and all allowances previously held by GenOn; and (2) allowances allocated to individual plants within the GenOn System. Only to the extent that such allowances are insufficient to establish compliance with the requirements of those SIPs, GenOn may use NO\textsubscript{X} Allowances purchased or otherwise obtained from sources outside the GenOn System.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 61.]

6. Except as provided in this Consent Decree, GenOn shall not sell or trade any NO\textsubscript{X} Allowances allocated to the GenOn System that would otherwise be available for sale or trade as a result of GenOn’s compliance with any of the NO\textsubscript{X} emission limitations specified in this Consent Decree.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 62.]

7. Provided that GenOn is in compliance with all of the NO\textsubscript{X} emission limitations specified in the Consent Decree, including both unit-specific and system-wide emissions rates and plant-wide and system-wide tonnage limitations, nothing in this Consent Decree shall preclude GenOn from selling or transferring NO\textsubscript{X} Allowances allocated to the GenOn System that become available for sale or trade when, and only insofar as, both: (a) the total Ozone Season NO\textsubscript{X} emissions from all Units within the GenOn System are below System-Wide Ozone Season Tonnage Limitations for the applicable year, as specified in Paragraph 58; and (b) the annual NO\textsubscript{X} emissions from all Units within the GenOn System are below the System-Wide Annual Tonnage Limitations, as specified in Paragraph 57.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 63.]

8. In no event shall the emission reductions required by this Decree be considered as credible contemporaneous emission decreases for the purpose of obtaining a netting credit under the Clean Air Act’s Nonattainment NSR and PSD programs.
9. In order to sell or transfer NO\textsubscript{X} Allowances pursuant to Paragraph 63, GenOn must also timely report the generation of such NO\textsubscript{X} Allowances in accordance with Section IX (Periodic Reporting) of this Consent Decree.

10. For purpose of this Subsection, the “surrender of allowances” means permanently surrendering NO\textsubscript{X} Allowances from the accounts administered by Plaintiffs for all Units in the GenOn System, so that such allowances can never be used to meet any compliance requirement of any person under the Clean Air Act, the Maryland and Virginia SIPs, or this Consent Decree.

11. For each calendar year beginning with calendar year 2004, GenOn shall surrender to EPA, or transfer to a non-profit third party selected by GenOn for surrender: (1) the number of Ozone Season NO\textsubscript{X} allowances equal to the amount by which the Ozone Season NO\textsubscript{X} allowances allocated to all GenOn System Units for a particular ozone season are greater than the System-Wide Ozone Season Tonnage Limitations for NO\textsubscript{X} established in Paragraph 58 of the Consent Decree for the same year; and (2) the number of “annual” (non-ozone season) NO\textsubscript{X} allowances equal to the amount by which the “annual” NO\textsubscript{X} allowances allocated to all GenOn System Units for a particular non-ozone season are greater than the difference between the System-Wide Annual Tonnage Limitations for NO\textsubscript{X} established in Paragraph 57 and the System Wide Ozone Season Tonnage Limitations for NO\textsubscript{X} established in Paragraph 58 for that same year.

12. If any NO\textsubscript{X} Allowances are transferred directly to a non-profit third party, GenOn shall include a description of such transfer in the next report submitted to Plaintiffs. Such report shall: (a) provide the identity of the non-profit third party recipient(s) of the NO\textsubscript{X} Allowances and a listing of the serial numbers of the transferred NO\textsubscript{X} Allowances; and (b) include a certification by the third-party recipient(s), stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NO\textsubscript{X} Allowances and will not use any of the Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NO\textsubscript{X} Allowances, GenOn shall include a statement that the third-party recipient(s) tendered the NO\textsubscript{X} Allowances for permanent surrender to Plaintiffs in accordance with the provisions of Paragraph
68 within one (1) year after GenOn transferred the NO\textsubscript{X} Allowances to them. GenOn shall not have complied with the NO\textsubscript{X} Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred NO\textsubscript{X} Allowances to Plaintiffs.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 67]

13. For all NO\textsubscript{X} Allowances surrendered to Plaintiffs, GenOn or the non-profit third-party recipient(s) (as the case may be) shall first submit a NO\textsubscript{X} Allowance transfer request form to EPA directing the transfer of such NO\textsubscript{X} Allowances to the Plaintiffs’ Enforcement Surrender Account or to any other Plaintiffs account that Plaintiffs may direct in writing. As part of submitting these transfer requests, GenOn or the third-party recipient(s) shall irrevocably authorize the transfer of these NO\textsubscript{X} Allowances and identify- by name of account and any applicable serial or other identification numbers or station names- the source and location of the NO\textsubscript{X} Allowances being surrendered.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 68]

Severance of the Morgantown and/or Dickerson Plants from the GenOn System

14. GenOn shall comply with paragraphs 185,186,187,188,189,190,191,192,193,194,195 of Section XIX. Severing the Morgantown Plant: Revised System-wide NO\textsubscript{X} Emission Limitations, Section XX. Severing the Dickerson Plant: Revised System-wide NO\textsubscript{X} Emission Limitations, XXI Severing the Morgantown and Dickerson Plants: Revised System-wide NO\textsubscript{X} Emission Limitations, and Section XXII. Sales or Transfers of Ownership Interests.

[Reference: GenOn Potomac River Consent Decree, Sections XIX, XX, XXI, and XXII]

15. GenOn shall comply with the reporting requirements of paragraph 138 and 139 of Section XVII Severance of the Morgantown and/or Dickerson Plants from the GenOn System.

[Reference: GenOn Potomac River Consent Decree, Section XVII, paragraphs 138 and 139]

Monitoring, and Record Keeping and Reporting Requirements

16. In determining Emission Rates for NO\textsubscript{X}, GenOn shall use CEMs in accordance with those reference methods specified in 40 CFR Part 75.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 69]

17. GenOn shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and document (including records and documents in electronic form) now in its or its contractors’ or agents’ possession
or control, and that directly relate to GenOn’s performance of its obligations under this Consent Decree until December 31, 2015. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 131]

18. GenOn shall submit a report to Plaintiffs containing a summary of the data recorded by each NOx CEMs in the GenOn System, expressed in lb/mmBtu, on a 30-day rolling average basis, in electronic format, within 30 days after the end of each calendar quarter and within 30 days after the end of each month of the Ozone Season, and shall make all data recorded available to the Plaintiffs upon request.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 70]

Completed (19, 20 & 21): [Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 88, 89 & 90]

22. In addition to the progress reports required pursuant to this Section, GenOn shall provide a written report to Plaintiffs of any violation of the requirements of this Consent Decree, including exceedances of any Unit-specific 30-Day Rolling Average Emission Rates, Unit-specific 30-Day Rolling Average Removal Efficiencies, any Unit-specific 12-Month Rolling Average Removal Efficiencies, System-Wide Annual Tonnage Limitations, System-Wide Ozone Season Tonnage Limitations, Potomac River Annual or Ozone Season Tonnage Limitations, or System-Wide Ozone Season Emission Rate, within ten (10) business days of when GenOn knew or should have known of any such violation. In this report, GenOn shall explain the cause or causes of the violation and all measures taken or to be taken by GenOn to prevent such violations in the future.

[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 91]

23. Each GenOn report shall be signed by GenOn’s Director, Environmental Safety and Health, GenOn Mid-Atlantic, LLC, or in his or her absence, the President of GenOn Mid-Atlantic, LLC, or higher ranking official, and shall contain the following certification

This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is
true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States. [Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 92]

24. If any Allowances are surrendered to any non-profit third party, in accordance with this Consent Decree, the third party’s certification shall be signed by a managing officer of the third party and shall contain the following language:

I certify under penalty of law that [name of third party] will not sell, trade, or otherwise exchange any of the [NOx, SO2, or Mercury] Allowances and will not use any of the Allowances to meet any obligation imposed by an environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States. [Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 93]

Emissions Unit Number(s): D-1, D-2, & D-3: Boilers Cont’d

CAM Plan for Dickerson Generating Station D-1, D-2 and D-3 (By-Pass Stack)
Dickerson Unit 1, 2 & 3 PM Emission Control

Dickerson facility has three (3) identical base-load coal fired steam generating units each nominally rated at 191 MW. The Dickerson baghouse serves a portion of the gas flow from all three units. There are three ESPs, each ESP is dedicated to a single unit and serves a portion of that gas flow for that unit. In the normal mode of operation, combustion gases from the three boilers, combine and are discharged to the atmosphere through a common 700-foot stack.

Rationale for Selection of Performance Indicators
CAM PM stack testing was performed by TRC Environmental on Dickerson Units during July 2008. These results were used as the basis for determining the performance indicator selection and range.

A linear regression correlation ($R^2$) of 0.9162 was calculated between the actual opacity and the PM emission data as shown in Fig 2 of the CAM Plan. This shows a high correlation between opacity and PM emissions. At the 10.0 percent opacity limit, the PM emissions is predicted to be about 0.0186 grains/scfd which is significantly below Dickerson Units’ 0.03 grains/scfd emission limit.
The use of opacity as the indicator range value of 9.8 percent on a block 1-hour average was selected to avoid approaching the opacity standard while still maintaining the PM emission standard well below the established standard. At 9.8 percent opacity is calculated PM emission to be 40 percent below Dickerson PM emissions limit of 0.03 grains/scfd. Therefore, an indicator range set at 9.8 percent opacity is deemed to have sufficient margin to allow for the plant operations to take corrective measures to avoid any exceedance of the PM emission while still maintaining the opacity standard.

**Monitoring Approach**

The measurement of opacity at the Dickerson common stack was selected as the CAM PM performance indicator. The stack test data show a high correlation between the opacity and PM emissions. It can reasonably be assumed that if opacity is maintained below 9.8 percent then the PM emissions are well below the Dickerson’s PM standard.

When opacity levels equal to or greater than 9.8 percent on a block 1-hour average are observed at the Dickerson common stack the operator will be required to review the operations and performance of both ESPs and Baghouse in order to reduce the opacity. The operator will use a troubleshooting chart provided to review the ESP and Baghouse operations and performance to ensure proper operation of both PM control equipment.

All block 1-hour periods greater than or equal to 9.8 percent will be recorded and all ESP and Baghouse corrective actions including their results will be documented. This data will be provided to the Department on a quarterly basis.

**Emissions Unit Number(s): FGD System for D-1 D-2 and D-3**

A wet flue gas desulfurization (FGD) system is installed on D-1, D-2 and D-3. The FGD system controls acid gases (SO₂ & HCl) and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing a gypsum by-product. The FGD system consists of the following subsystems: 1. Limestone unloading and storage facilities; 2. Limestone slurry preparation and feed; 3. SO₂ absorption tower; 4. Gypsum dewatering and loading facilities; and 5. Two emergency diesel engines. CPCN 9087 was issued on July 19, 2007 [CPCN: 9087]

**Applicable Standards and Limitations:**

[Reference: CPCN 9087: II. Applicable Air Quality Regulations]

10. The Dickerson facility is subject to all applicable, federally enforceable State air quality requirements including, but not limited to, the following regulations:
a) **COMAR 26.11.01.10**—Requires GenOn to install Continuous Opacity Monitoring (COM) systems to monitor opacity and Continuous Emissions Monitoring (CEM) systems (COMAR 26.11.01.11) to monitor SO₂, NOₓ and either O₂ or CO₂ from each boiler, and to meet applicable CEM installation, certification, operating, monitoring, testing, and, malfunction requirements in 40 CFR Part 60, 40 CFR Part 75, and 40 CFR Part 51, Appendix P, §3.3-3.8 or §3.9 as incorporated by reference.

b) **COMAR 26.11.03.19**—Requires GenOn to update the existing Part 70 Operating Permit [No. 24-031-00019] to include applicable APC Project requirements.

c) **COMAR 26.11.06.02C(2)**—Prohibits GenOn from causing or permitting the discharge of emissions from any installation or building (i.e., confined, non-fuel-burning equipment sources) other than water in an uncombined form, which are visible to human observers. The visible emissions standard do not apply to emissions during startup and process modifications or adjustments, or occasional cleaning of control equipment, if (a) the visible emissions are not greater than 40% opacity; and (b) the visible emissions do not occur for more than 6 consecutive minutes in any 60-minute period.

d) **COMAR 26.11.06.03B(2)(a)**—Prohibits GenOn from discharging into the outdoor atmosphere from any non-fuel burning confined source (i.e., the limestone, gypsum and other material storage silos, enclosed material transfer points, etc) particulate matter in excess of 0.03 grains per dry standard cubic feet (gr/scfd)(68.7 mg/dscm).

e) **COMAR 26.11.06.03C(1)**—Prohibits GenOn from causing or permitting emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne.

f) **COMAR 26.11.06.03D**—Prohibits GenOn from causing or permitting any material to be handled, transported, or stored, or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. For the unloading, loading and transfer of the materials included at the Dickerson APC Project (limestone, gypsum, sorbent to control sulfuric acid mist emissions, and hydrated lime in wastewater treatment plant operations), these reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer:

i) Use of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land.

ii) Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can create airborne dusts.

iii) Installation and use of hoods, fans, and dust collectors to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting of buildings or other similar operations.
iv) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution. Alternate means may be employed to achieve the same results as would covering the vehicles.

v) The paving of roadways and their maintenance in clean condition.

vi) The prompt removal from paved streets of earth or other material which has been transported there by trucks or earth moving equipment or erosion by water.

g) **COMAR 26.11.06.12**-Prohibits GenOn from constructing, modifying or operating or causing to be constructed, modified, or operated, a New Source Performance Standard (NSPS) source as defined in COMAR 26.11.01.01C, which results in violation of provisions of 40 CFR Part 60.

h) **COMAR 26.11.09.03**-When determining compliance with applicable particulate matter emission standards from boiler stacks (concentration requirement expressed as grains per standard cubic foot or milligrams per cubic meter of dry exhaust gas), GenOn shall correct to 50 percent excess air. In addition, when determining compliance with a mass-based particulate matter emission limit expressed as pounds per million Btu (lb/MMBtu), GenOn shall use the procedures for determining particulate matter emission rates in 40 CFR Part 60 Appendix A, Method 19.

i) **COMAR 26.11.09.05E(2) through E(4)**-Prohibits the discharge of emissions from quench pump engine when operating at idle, greater than 10 percent opacity, and when in operating mode, greater than 40 percent opacity. Exceptions: (i) limitations when operating at idle do not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system; (ii) limitations when operating at idle do not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods: engines that are idled continuously when not in service: 30 minutes and all other engines: 15 minutes; (iii) limitations when in idle and operating modes do not apply while maintenance, repair, or testing is being performed by qualified mechanics.

j) **COMAR 26.11.009.06B(3)**-Prohibits GenOn from discharging particulate matter into the atmosphere caused by the combustion of solid fuel in Units 1, 2, and 3 in excess of 0.03 gr/dscf, corrected to 50% excess air.

k) **COMAR 26.11.09.07A(2)(b)**-Prohibits GenOn from burning distillate fuel oil in the quench pumps with a sulfur content greater than 0.3 percent.

l) **COMAR 26.11.27**-Requires GenOn to comply with the applicable emissions limitations for NOX, SO2 and mercury, and the monitoring and record keeping requirements contained in COMAR 26.11.27.


12. The equipment at Dickerson identified in [CPCN 9087] Tables 1a, 1b and 2 are subject to NSPS 40 CFR Part 60, Subpart OOO-Standards of Performance for Non-metallic Mineral Processing Plants (40 CFR §60.670) and the associated
notification and testing requirements of 40 CFR §60.7, §60.8 and §60.11 whose requirements include, but are not limited to the following:

a) GenOn shall not cause to be discharged into the atmosphere gases from any transfer point along the belt conveyor systems, or any other stack, particulate matter in concentrations greater than 0.022 gr/dscf or opacity that is greater than seven percent.

b) GenOn shall not cause to be discharged into the atmosphere from any transfer point along the belt conveyor system or from any other affected facility any fugitive emissions which exhibit greater than 10 percent opacity. If the transfer point is totally enclosed in a building or enclosure, then there are no fugitive emissions allowed from the building unless they are directed through a vent, which is limited by Condition 12(a).

c) GenOn shall not cause to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions which exhibit greater than 15 percent opacity.

d) GenOn shall not cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity.

13. The 252-horsepower diesel engine-driven quench pump and the 227-horsepower diesel fire pump at the Dickerson facility are subject to New Source Performance Standards (NSPS) 40 CFR Part 60, Subpart III – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR §60.4205) and the associated fuel, monitoring, compliance, testing, notification, reporting and record keeping requirements (40 CFR §60.4200 et seq.), and related applicable provisions of 40 CFR §60.7 and §60.8.

[Reference: CPCN 9087: IV. Operational Restrictions and Limitations]

14. GenOn shall:

a) Install, maintain and operate the new limestone, gypsum, unloading, storage, transfer and distribution equipment and systems with associated particulate matter control methods listed in [CPCN 9087] Tables 1a-b and Table 2 in accordance with vendor recommendations and best management practices, and in such a manner as to ensure full and continuous compliance with all applicable regulations.

b) At least 60 days prior to the initial start-up date, prepare and submit to the PSC and ARMA a Best Management Practices (BMP) Plan for the new limestone, gypsum, SAM control sorbent, and hydrated lime transfer, storage and distribution equipment listed in [CPCN 9087] Tables 1a-b and Table 2 that contains an explanation of reasonable precautions that will be used to prevent particulate matter from this equipment from becoming airborne. The Plan shall include a description of the types and frequency of inspections and/or preventative maintenance (PM) that will be conducted. In addition, GenOn shall
define the associated records that will be maintained to document that inspections and PMs have been conducted as proposed. Completed

c) At least 60 days prior to replacing, elimination or in any manner changing any of the particulate control systems listed in [CPCN 9087] Table 1a-b and Table 2, GenOn shall submit a request to ARMA to amend the facility’s BMP Plan. The request shall specify the proposed change(s) in emissions control systems; shall demonstrate that the change(s) will not result in any increases in any pollutants; and update [CPCN 9087] Tables 1a-b and Table 2 of this CPCN. GenOn shall be authorized to make the changes proposed in the written request unless ARMA denies the request within 30 days of the receipt of the request.

Compliance Demonstration

[Reference: CPCN 9087: V. Testing]
17. In accordance with COMAR 26.11.01.04A, GenOn may be required by ARMA to conduct additional stack tests to determine compliance with applicable air quality requirements.

[Reference: CPCN 9087: VI. Monitoring]
18. GenOn shall operate continuous emissions monitoring system (CEMS) for SO₂, NOₓ and either oxygen or CO₂ as required under 40 CFR part 75 and continuous opacity monitoring systems (COMS) for Dickerson Units 1, 2 and 32.

[Reference: CPCN 9087: VII. Recordkeeping and Reporting]
24. All records and logs required by this CPCN shall be maintained at the facility for at least 5 years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of ARMA.

[Reference: CPCN 9087: VII. Recordkeeping and Reporting]
20. GenOn shall submit to ARMA and US EPA written reports of the results of all performance test conducted to demonstrate compliance with the standards set forth in applicable NSPS within 60 days of completion of the tests.

21. Final results of the performance tests required by this CPCN must be submitted to ARMA within 60 days after completion of the test. Analytical data shall be submitted to ARMA directly from the emission testing company.

25. All air quality notification and reports required by this CPCN shall be submitted to:

   Administrator, Compliance Program
   Air and Radiation Management Administration
   1800 Washington Boulevard
   Baltimore, Maryland 21230
26. All notification and reports required by 40 CFR 60 Subpart OOO and Subpart III and 40 CFR 63, unless specified otherwise, shall be submitted to:

Regional Administrator, US EPA
Region III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Emissions Unit Number(s): SNCR System for D-1 D-2 and D-3
A Selective Non-Catalytic Reduction (SNCR) system is installed on Dickerson Units 1, 2, and 3. The SNCR system is to control NO\textsubscript{X} emissions. The SNCR system is a post combustion NO\textsubscript{X} reduction method through the controlled injection of Urea into the combustion gases of the boilers. The SNCR system consists of the following subsystems: 1. Reagent unloading and storage facilities; 2. Distribution and control modules; and 3. Two levels of wall injectors on each boiler. (Maryland’s Healthy Air Act (HAA) and the NO\textsubscript{X} Reduction and Trading Program). [CPCN: 9140]

Applicable Standards and Limitations:
[Reference: CPCN 9140: II. Applicable Air Quality Regulations]
9. The Dickerson facility is subject to all applicable, federally enforceable State air quality requirements including, but not limited to, the following regulations:
   a) COMAR 26.11.01.10—Requires GenOn to install Continuous Opacity Monitoring (COM) systems to monitor opacity and Continuous Emissions Monitoring (CEM) systems (COMAR 26.11.01.11) to monitor SO\textsubscript{2}, NO\textsubscript{X} and either O\textsubscript{2} or CO\textsubscript{2} from each boiler, and to meet applicable CEM installation, certification, operating, monitoring, testing, and, malfunction requirements in 40 CFR Part 60, 40 CFR Part 75, and 40 CFR Part 51, Appendix P, §3.3-3.8 or §3.9 as incorporated by reference.
   b) COMAR 26.11.03.18—Requires GenOn to update the existing Part 70 Operating Permit to include applicable SNCR Project requirements.
   c) COMAR 26.11.06.02C(2)—Prohibits GenOn from causing or permitting the discharge of emissions from any installation or building (i.e., confined, non-fuel-burning equipment sources) other than water in an uncombined form, which are visible to human observers.
   d) COMAR 26.11.06.03B(2)(a)—Prohibits GenOn from discharging into the outdoor atmosphere from any confined source particulate matter in excess of 0.03 grains per dry standard cubic feet (gr/scfd)(68.7 mg/dscm).
   e) COMAR 26.11.06.03C(1)—Prohibits GenOn from causing or permitting emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne,
   f) COMAR 26.11.06.03D—Prohibits GenOn from causing or permitting any material to be handled, transported, or stored, or a building, its appurtenances, or
a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne.

g) COMAR 26.11.09.03-When determining compliance with applicable particulate matter emission standards from boiler stacks (concentration requirement expressed as grains per standard cubic foot or milligrams per cubic meter of dry exhaust gas), GenOn shall correct to 50 percent excess air.

h) COMAR 26.11.09.05A(2)-Prohibits GenOn from causing or permitting the discharge of emissions from Dickerson Units 1, 2, and 3, other than water in an uncombined form, which are visible to the human observers. The visible emissions standard do not apply to emissions during startup and process modifications or adjustments, or occasional cleaning of control equipment, if (a) the visible emissions are not greater than 40% opacity; and (b) the visible emissions do not occur for more than 6 consecutive minutes in any 60-minute period.

i) COMAR 26.11.009.06B(3)-Prohibits GenOn from discharging particulate matter into the atmosphere caused by the combustion of solid fuel in Units 1, 2, and 3 in excess of 0.03 gr/dscf, corrected to 50% excess air.

j) COMAR 26.11.09.08C(2)(e)-Prohibits GenOn from discharging NO\textsubscript{X} emissions from Units 1, 2, and 3 in excess of 0.70 lb/MMBtu per hour of heat input.

k) COMAR 26.11.27-Requires GenOn to comply with the applicable emissions limitations for NO\textsubscript{X}, SO\textsubscript{2} and mercury, and the monitoring and record keeping requirements contained in COMAR 26.11.27.

11. GenOn shall limit the emissions of NO\textsubscript{X} from Units 1, 2 and 3 to 0.4 lb/MMBtu on an annual average basis (Phase II Acid Rain permit – 40 CFR §76.7(a)(1)).

Compliance Demonstration

[Reference: CPCN 9140: III. Monitoring and Testing Requirements]

14. GenOn shall conduct an initial stack emission test to measure NO\textsubscript{X} emissions from Units 1, 2 and 3 within 180 days of start-up of the SNCR system. Alternately, GenOn may request permission from MDE-ARMA to utilize the CEM required in Condition 12 for the initial emission test to measure NO\textsubscript{X}.

15. At least 30 working days before initial stack tests for NO\textsubscript{X} are conducted, GenOn shall submit to MDE-ARMA a test protocol for review and approval. For any subsequent stack tests for NO\textsubscript{X}, GenOn shall either notify MDE-ARMA that the earlier approved protocol is to be used or shall submit a revised protocol for review and approval.

16. Within 60 days of completing the stack tests for NO\textsubscript{X}, GenOn shall provide MDE-ARMA copies of the testing results.

[Reference: CPCN 9140: III. Monitoring and Testing Requirements]

12. The common stack for Units 1, 2, and 3 shall be equipped with a continuous emissions monitoring system (CEMS) for NO\textsubscript{X} that is installed, calibrated, operated, and certified in accordance with 40 CFR Part 75.
13. Compliance with the visible emissions standards for Units 1, 2 and 3 shall be demonstrated by installation and operation of a continuous opacity monitor that is certified in accordance with 40 CFR Part 60, Appendix B and that meets the quality assurance criteria of MDE-ARMA’s Air Management Administration Technical Memorandum 90-01, “Continuous Emission Monitoring (CEM) Policies and Procedures” (October 1990) (Performance Specification 2), provided the aforesaid Technical Memorandum is applicable and operative, unless and until GenOn is no longer required by law to monitor opacity continuously.

[Reference: CPCN 9140: IV. Recordkeeping and Reporting Requirements]

17. The following records related to operation of the SNCR on Units 1, 2 and 3, with supporting documentation, shall be maintained on site for at least five years and made available to MDE-ARMA upon request:
   a) Total NO\(_X\) emissions (tons) for each calendar month separately for each Unit 1, 2 and 3.
   b) NO\(_X\) emission rate, pounds per million Btu of heat input separately for each Unit 1, 2 and 3.
   c) All stack emission test reports.
   d) All CEM emission monitoring data.
   e) All CEM certification and calibration results; and
   f) Records of any repairs and maintenance made to the SNCR emission control device and CEM systems.

18. GenOn shall furnish written notification to MDE-ARMA of the following events related to the SNCR system for Units 1, 2 and 3:
   a) the date construction commenced within 30 days after such date.
   b) the anticipated project startup date, not more than 60 or less than 30 days prior to such date.
   c) the actual startup date within 15 days after such date; and
   d) the anticipated date of compliance stack testing at least 30 days prior to such date.

19. All air quality records and logs required by this permit (CPCN 9140) shall be maintained at the facility for at least 5 years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of ARMA.

[Reference: CPCN 9140: IV. Recordkeeping and Reporting Requirements]

20. All air quality notifications and reports required by this CPCN shall be submitted to:

   Administrator, Compliance Program
   Maryland Department of the Environment
   Air and Radiation Management Administration
   1800 Washington Boulevard
   Baltimore, Maryland 21230
Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d
Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003)

Please Note: On June 29, 2015, the Supreme Court issued an opinion in Michigan et al v. Environmental Protection Agency. The Supreme Court’s decision remands the MATS rule to EPA and returns the matter to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. As of the issuance of this permit, the MATS rule is in effect. The Supreme Court decision in Michigan requires the EPA to undertake additional proceedings for the limited purpose of evaluating costs for its “appropriate and necessary” finding which preceded the MATS rule. Until and unless the MATS rule is stayed and/or vacated by the D.C. Circuit, MATS related conditions in the Title V permit apply. If the MATS rule is stayed and/or vacated or partially stayed and/or vacated then the affected conditions in the Title V permit will be revised/removed accordingly.

Compliance Status
GenOn submitted to the Department its initial MACT notification (40 CFR 63 Subpart UUUUU – Coal & Oil-fired Electric Utility Steam Generating Units) for their (3) electrical generating stations (Morgantown, Dickerson and Chalk Point) located in Maryland. The report was received by the Department on August 20, 2012.

Mercury and Air Toxic Standards (MATS) Performance Tune-up was conducted as follows:
Unit D-1: Start date: April 13, 2013 and Completion date: May 22, 2013. (Dated May 4, 2015)
Unit D-3: Start date: April 12, 2014 and Completion date: May 5, 2014. (Dated May 4, 2015)

Applicable Standards and Limitations:
Control of HAPs Emissions

§63.9980 - What is the purpose of this subpart? This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired
electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

_Electric utility steam generating unit (EGU)_ means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

§63.9981 - Am I subject to this subpart?

“You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart.”

§63.9984 - When do I have to comply with this subpart?

“(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.”

“(c) You must meet the notification requirements in §63.10030 according to the schedule in §63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.”

“(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.”

§63.9991 - What emission limitations, work practice standards, and operating limits must I meet?

“(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under §63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in §63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO\(_2\) limit in Tables 1 and 2 to this subpart only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO\(_2\) continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with §63.10000(b).”

General Compliance Requirements

§63.10000 - What are my general requirements for complying with this subpart?
“(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU s, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.”

“(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(iv) If your coal-fired or solid oil derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO₂) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO₂ emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

“(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of
your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of §63.10010. Using the process described in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section. Note the SO₂ CEM is covered by existing monitoring plan under 40 CFR Part 75. The PEMS and Hg monitoring plans were submitted to the Department and EPA in October 2014.

(d)(4) You must operate and maintain the CMS according to the site-specific monitoring plan.”

“(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to §63.10021(e).”

“(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distribution system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR Part 60, Subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.”

“(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational
as of the date your source ceases to be or becomes subject to this subpart. All
calibration and drift checks must be performed as of the date your source ceases
to be or becomes subject to this subpart. You must also comply with provisions
of §§63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests
must be performed as of the performance test deadline for PM CEMS, if
applicable. Relative accuracy testing for other CEMS need not be repeated if
that testing was previously performed consistent with CAA section 112
monitoring requirements or monitoring requirements under this subpart.
(l) On or before the date an EGU is subject to this subpart, you must install,
certify, operate, maintain, and quality assure each monitoring system necessary
for demonstrating compliance with the work practice standards for PM or non-
mercury HAP metals during startup periods and shutdown periods. You must
collect, record, report, and maintain data obtained from these monitoring
systems during startup periods and shutdown periods.”

Compliance Demonstration

Testing and Initial Compliance Requirements

§63.10005 - What are my initial compliance requirements and by what date must
I conduct them?

(a) General requirements. For each of your affected EGUs, you must
demonstrate initial compliance with each applicable emissions limit in Table 1 or
2 of this subpart through performance testing. Where two emissions limits are
specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and
an electrical output-based limit in lb/MWh), you may demonstrate compliance
with either emission limit. For a particular compliance demonstration, you may be
required to conduct one or more of the following activities in conjunction with
performance testing: collection of hourly electrical load data (megawatts);
establishment of operating limits according to §63.10011 and Tables 4 and 7 to
this subpart; and CMS performance evaluations. In all cases, you must
demonstrate initial compliance no later than the applicable date in paragraph (f)
of this section for tune-up work practices for existing EGUs, in §63.9984 for other
requirements for existing EGUs, and in paragraph (g) of this section for all
requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table
1 or 2 to this subpart using stack testing, the initial performance test generally
consists of three runs at specified process operating conditions using approved
methods. If you are required to establish operating limits (see paragraph (d) of
this section and Table 4 to this subpart), you must collect all applicable
parametric data during the performance test period. Also, if you choose to
comply with an electrical output-based emission limit, you must collect hourly
electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP
concentrations directly ( i.e., an Hg, HCl, or HF CEMS, or a sorbent trap
monitoring system) or an SO₂ or PM CEMS, the initial performance test consists
of 30 boiler operating days of data collected by the initial compliance demonstration date specified in §63.10005 with the certified monitoring system.  

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO\textsubscript{2} emissions limit in Table 1 or 2 to this subpart.  

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.  

(b) Performance testing requirements. If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to §63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in §63.9984, provided that the following conditions are fully met:  

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in §63.9984;  

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;  

(3) The performance test was conducted in accordance with all applicable requirements in §63.10007 and Table 5 to this subpart;  

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and  

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted."

“(d) CMS requirements. If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.  

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO\textsubscript{2}, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO\textsubscript{2}, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart.
through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO₂, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (NOTE: For this calculation, the term \(E_{ij}\) in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).”

“(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) **Tune-ups.** All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to §63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in §63.9984 and according to the applicable provisions in §63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.
§63.10006 - When must I conduct subsequent performance tests or tune-ups?

“(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under §63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and §63.10007 at least every year.”

“(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, §63.10007, and §63.10000(c), except as otherwise provided in §63.10021(d)(1).”

“(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in §63.10021(d)(1).”

“(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in §63.10031.”

§63.10007 - What methods and other procedures must I use for the performance tests?

“(a) Except as otherwise provided in this section, you must conduct all required performance tests according to §63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(1) If you use CEMS (Hg, HCl, SO₂, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.
(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

“(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO\textsubscript{2} ppm by \(1.66 \times 10^{-7}\);
(ii) Multiply HCl ppm by \(9.43 \times 10^{-8}\);
(iii) Multiply HF ppm by \(5.18 \times 10^{-8}\);
(iv) Multiply HAP metals concentrations (mg/dscm) by \(6.24 \times 10^{-8}\); and
(v) Multiply Hg concentrations ($\mu$g/scm) by $6.24 \times 10^{-11}$.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of $K$ with $1.66 \times 10^{-7}$ lb/scf-ppm for SO$_2$, $9.43 \times 10^{-8}$ lb/scf-ppm for HCl (if an HCl CEMS is used), $5.18 \times 10^{-8}$ lb/scf-ppm for HF (if an HF CEMS is used), or $6.24 \times 10^{-8}$ lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining $C_h$ as the average SO$_2$, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the $10^3$ term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO$_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

(1) Diluent cap values. If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO$_2$ concentration is below the cap value or the measured O$_2$ concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for CO$_2$ or 19% for O$_2$.

(ii) For all other EGUs, you may use 5% for CO$_2$ or 14% for O$_2$.

(2) Default electrical load. If you use CEMS to continuously monitor Hg, HCl, HF, SO$_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero electrical load, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable electrical output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter. This default electrical load is either the nameplate capacity of the EGU or the highest
electrical load observed in at least four representative quarters of EGU operation. For a monitored common stack, the default electrical load is used only when all EGUs are operating (i.e., combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default electrical load equal to 5% of the combined maximum sustainable electrical load of the EGUs that are operating but have a total of zero electrical load must be used to calculate the hourly electrical output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.”

§63.10010 - What are my monitoring, installation, operation, and maintenance requirements?

“(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) Single unit-single stack configurations. For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) Unit utilizing common stack with other affected unit(s). When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.”

“(4) Unit with a main stack and a bypass stack. If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.”

“(b) If you use an oxygen (O\textsubscript{2}) or carbon dioxide (CO\textsubscript{2}) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O\textsubscript{2} or CO\textsubscript{2} concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the
CEMS according to part 75 of this chapter. Use only quality-assured O₂ or CO₂ data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from §75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) Not Applicable.

(f)(1) If you use an SO₂ CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO₂ CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO₂ CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO₂ emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO₂ emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default electrical load and the diluent cap are available for use in the hourly SO₂ emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO₂ emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a
30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.”

“(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ±14 °C (320° ±25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality
assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;
(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;
(C) Any data recorded during periods of startup or shutdown.
(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.”
(j) Not Applicable.

§63.10011 - How do I demonstrate initial compliance with the emissions limits and work practice standards?
“(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.”
“(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with certified CEMS after the applicable date in §63.9984 (or, if applicable, prior to that date, as described in §63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.
(2) For a unit that uses a CEMS to measure SO₂ or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in §63.9984 (or, if applicable, prior to that date, as described in §63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO₂ or filterable PM emission limit in Table 1 or 2 to this subpart.”
“(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to §63.10030(e).
(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.
(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.
(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.
(1) You may use the diluent cap and default electrical load values, as described in §63.10007(f), during startup periods or shutdown periods.
(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.
(3) You must report the information as required in §63.10031.
(4) If you choose to use paragraph (2) of the definition of “startup” in §63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of “startup” in §63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.
   (i) As mentioned in §63.6(g)(1), the request will be published in the FEDERAL REGISTER for notice and comment rulemaking. Until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in §63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard.
   (ii) The request need not address the items contained in §63.6(g)(2).
   (iii) The request shall provide evidence of a documented manufacturer-identified safely issue.
   (iv) The request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.
   (v) In addition, the request shall contain documentation that:
      (A) The EGU is using clean fuels to the maximum extent possible to bring the EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in the EGU;
      (B) The EGU has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and
      (C) Identifies with specificity the details of the manufacturer's statement of concern.
   (vi) The request shall specify the other work practice standards the EGU owner or operator will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.
   (vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.”

Continuous Compliance Requirements
§63.10020 - How do I monitor and collect data to demonstrate continuous compliance?
“(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10000(d).
(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

(e) Additional requirements during startup periods and shutdown periods

(1) During each period of startup, you must record for each EGU:
   (i) The date and time that clean fuels being combusted for the purpose of startup begins;
   (ii) The quantity and heat input of clean fuel for each hour of startup;
   (iii) The electrical load for each hour of startup;
   (iv) The date and time that non-clean fuel combustion begins; and
   (v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:
   (i) The date and time that clean fuels being combusted for the purpose of shutdown begins;
   (ii) The quantity and heat input of clean fuel for each hour of shutdown;
   (iii) The electrical load for each hour of shutdown;
   (iv) The date and time that non-clean fuel combustion ends; and
   (v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10011(l).”

“(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit or that has LEE status for filterable PM or
total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS you must:
(A) Record temperature and flow rate of post-combustion (exhaust) gas and amperage of forced draft fan(s) upstream of each filterable PM control device during each hour of startup.
(B) Record temperature and flow rate of exhaust gas and amperage of induced draft fan(s) downstream of each filterable control device during each hour of startup.
(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to fuel ratio and the differential pressure of the liquid during each hour of startup.”

§63.10021 - How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
“(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.
(b) Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO2, O2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

\[
\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} H_{ei}}{n} \quad (\text{Eq. 8})
\]

Where:
\(H_{ei}\) is the hourly emissions rate for hour \(i\) and \(n\) is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

“(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of §63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization.
during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

1. As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:
   (i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO\textsubscript{X} and CO must be installed within 3 calendar months after the burner inspection,
   (ii) Burner or combustion control component parts that do not affect the ability to optimize NO\textsubscript{X} and CO may be installed on a schedule determined by the operator;

2. As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

3. As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

4. As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

5. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O\textsubscript{2} probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

6. Optimize combustion to minimize generation of CO and NO\textsubscript{X}. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO\textsubscript{X} optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

7. While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO\textsubscript{X} in ppm, by volume, and
oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO\textsubscript{X} and O\textsubscript{2} monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO\textsubscript{X} in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in §63.10030) and electronically (as specified in §63.10031). Report the date of each subsequent tune-up electronically (as specified in §63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with §63.10031."

“(f) You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.
(h) You must keep records as specified in §63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown.”

Notification, Reports, and Records

§63.10032 - What records must I keep?

“(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

“(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.”

§63.10033 - In what form and how long must I keep my records?
“(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).
(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.”

Notification, Reports, and Records
§63.10030 - What notifications must I submit and when?
“(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.
(b) As specified in §63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.”
“(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.
(e) When you are required to conduct an initial compliance demonstration as specified in §63.10011(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.
(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.
(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.
(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.
(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with §63.10006(b), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in §63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) “This EGU complies with the requirements in §63.10021(a) to demonstrate continuous compliance.” and

(B) “No secondary materials that are solid waste were combusted in any affected unit.”

“(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of “startup” in §63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel and PM controls;

(C) Each design PM control device efficiency;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device;

(G) The design EGU uncontrolled PM emission rate in terms of pounds PM per hour;

(H) Each change from the original design that did or could have changed PM emissions, including, but not limited to, each different fuel mix, each revision to each PM control device, and each EGU revision, along with the month and year that the change occurred;
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21200 Martinsburg Road, Dickerson, Maryland 20842
Part 70 Operating Permit No. 24-031-0019
Permit Fact Sheet

(I) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls;
(J) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour;
(K) Current PM control device efficiency from each PM control device;
(L) Current time from start of fuel combustion to conditions necessary for each PM control device startup;
(M) Current PM control device efficiency upon startup of each PM control device; and
(N) Current EGU uncontrolled PM emission rate in terms of pounds PM per hour.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located. Apart from preparing, signing, and sealing this report, the professional engineer shall be independent and not otherwise employed by your company, any parent company of your company, or any subsidiary of your company."

§63.10031 - What reports must I submit and when?

“(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.
(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.
(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.9984.
(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.9984.
(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance
reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

1. The information required by the summary report located in 63.10(e)(3)(vi).
2. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

3. Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

4. Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to §63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 (or 48) months and was delayed until the next scheduled unit shutdown.

5. For each instance of startup or shutdown:
   i. Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of §63.10032(f).
   ii. Include the information required to be monitored, collected, or recorded according to the requirements of §63.10020(e).
   iii. If you choose to use CEMS for compliance purposes, include hourly average CEMS values and hourly average flow rates. Use units of milligrams per cubic meter for PM CEMS, micrograms per cubic meter for Hg CEMS, and ppmv for HCl, HF, or SO2 CEMS. Use units of standard cubic meters per hour on a wet basis for flow rates.
   iv. If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration in terms of micrograms per cubic meter.
   v. If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in §63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR
71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) On or after April 16, 2017, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA’s WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA’s Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA’s Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) On or after April 16, 2017, within 60 days after the date of completing each CEMS (SO₂, PM, HCl, HF, and Hg) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA’s WebFIRE database by using CEDRI that is accessed through EPA’s CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of EPA’s Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd.,
Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in §63.2 and as required in this chapter.

(2) On or after **April 16, 2017**, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX ([www.epa.gov/cdx](http://www.epa.gov/cdx)). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO₂ CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and §63.10021(f).

(4) On or after **April 16, 2017**, submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX ([www.epa.gov/cdx](http://www.epa.gov/cdx)). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

(6) Prior to **April 16, 2017**, all reports subject to electronic submittal in paragraphs (f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

(i) The facility name, physical address, mailing address (if different from the physical address), and county;

(ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;
(iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;
(iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;
(v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;
(vi) The identification of each emission point to which the report applies. An “emission point” is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., “Unit 2 stack,” “common stack CS001,” or “multiple stack MS001”);
(vii) The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;
(viii) The pollutant(s) being addressed in the report;
(ix) The reporting period being covered by the report (if applicable);
(x) The relevant test method that was performed for a performance test (if applicable);
(xi) The date the performance test was conducted (if applicable); and
(xii) The responsible official's name, title, and phone number.

If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.”

Emissions Unit Number(s): D CT-1: Combustion Turbine

One (1) Pratt and Whitney FT4-A combustion turbine rated at 18 megawatts, fires No.2 fuel oil and utilized for black start and peaking service. [4-0907]

This combustion turbine was installed prior to subpart GG standards and therefore is not subject to 40 CFR Part 60, subpart GG and has no NOX controls.

The facility is a major source of HAPs. The CT is not subject to the requirements of 40 CFR Part 63, Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines since they were constructed prior to March 5, 2004.
Compliance Status
This CT operated 13 hours in 2013. Capacity factor was 0.37% for the CT for January 1, 2014 – October 23, 2014.

Applicable Standards and limits
A. Control of Visible Emissions
COMAR 26.11.09.05A(2) & (3) – Fuel Burning Equipment

“Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity”.

Exceptions. Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:
(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period.”

Compliance Demonstration
The Permittee shall verify that there are no visible emissions when operating. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period at least once every 168 hours of operation. If the turbine operates less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived.

The Permittee shall perform the following, if emissions are visible to human observer:
(a) inspect combustion control system and combustion turbine operations,
(b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and
(c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine.
(d) after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform a Method 9 observation once daily when combustion turbine is operating for 18 minutes until corrective action have eliminated visible emissions.

The Permittee shall maintain a copy of the visible emissions readings on site for at least five years and make available to the Department upon request.

The Permittee shall report incidents of visible emissions in accordance with permit condition 4, Section III, Plant Wide Conditions, “Report of Excess Emissions and Deviations”. [Reference: COMAR 26.11.03.06C]
Rationale for Periodic Monitoring:
Combustion turbines that burn No. 2 fuel oil rarely have visible emissions if properly operated and maintained. This turbine only operates about 100 hours per year. Little maintenance is required and there is more than sufficient time to perform maintenance.

B. Control of Sulfur Oxides
COMAR 26.11.09.07A(2) - Sulfur Content Limitations for Fuel.
“A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III and IV:
(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent.”

Compliance Demonstration
The Permittee shall obtain a certification from the fuel supplier indicating that the oil complies with the limitation on the sulfur content of the fuel oil. The Permittee shall maintain records of fuel supplier’s certification on site for at least five years and shall make records available to the Department upon request. [Reference: COMAR 26.11.03.06C]
The Permittee shall report fuel supplier certifications to the Department upon request. [Reference: COMAR 26.11.09.07C]

Rationale for periodic monitoring:
This strategy to certify sulfur content in oil is similar to the requirements for boilers under New Source Performance Standards, Subpart Dc.

C. Control of Nitrogen Oxides
COMAR 26.11.09.08G. - Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 Percent or Less, and Combustion Turbines with a Capacity Factor Greater than 15 Percent.
“(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) Not applicable; and
(e) Not applicable.”

Compliance Demonstration
The Permittee, if the turbines operate more than 500 hours, shall perform a combustion analysis and optimize combustion at least once annually. [Reference: COMAR 26.11.09.08G(1)(b)].
The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. The Permittee shall maintain records if the calculations of the capacity factors. [Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]
The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with the support documentation in the Annual Emission Certification Report. [Reference: COMAR 26.11.09.08G(1)(a) COMAR 26.11.03.06C].

Emissions Unit Number(s): H CT-1 & H CT-2: Combustion Turbines Cont’d

Two (2) General Electric Frame 7F combustion turbines each with a nominal rated capacity of 167 megawatts located at Station H. These combustion turbines fire primarily natural gas and No. 2 fuel oil as a secondary fuel. The units are equipped with inlet foggers to maintain output at high ambient temperatures and with water injection to control NO\textsubscript{X} emissions. [9-0362 & 9-0363]

These turbines were installed in 1992 and 1993 respectively. The units received a Certificate of Public Convenience (CPCN) Order No. 68851 Case 8063 issued July 2, 1990, which sets limits for annual emissions of carbon monoxide, PM\textsubscript{10}, total particulates, VOC, NO\textsubscript{X} and SO\textsubscript{2} expressed in tons. The project triggered a Prevention of Significant Deterioration (PSD) approval because the projected annual emissions of from the proposed project exceeded the major modification thresholds for NO\textsubscript{X}, CO, PM, and SO\textsubscript{2}. The application for the project was received prior to November 15, 1990 so the project did not trigger major new source review (NSR) for non-attainment for NO\textsubscript{X}.

The original proposal for Station H was a plant to be built in stages. Element I of the project was the construction of four simple cycle combustion turbines. Element II of the project called for the addition of two heat recovery steam
generators, one for each pair of combustion turbines. In addition, there was to be the addition of a small auxiliary boiler. Most of the project did not materialize. Only two simple cycle combustion turbines were ever constructed. The conditions in the CPCN that was issued for Station H that refer to Element II including the auxiliary boiler are null and obsolete.

The BACT determination for NO\textsubscript{X} for the project was to install water injection in the turbines to achieve a 42 ppm at 15% O\textsubscript{2} when firing natural gas and the following limits when firing No. 2 fuel oil:

for $N \leq 0.015$

and

$57 + 400N$ for $N > 0.015$

where $N$ is the nitrogen content of the fuel in percent by weight.

The BACT determination for SO\textsubscript{2} for the project was a restriction limiting the sulfur content in the No. 2 fuel oil burned in the combustion turbines and auxiliary boiler to not more than 0.3% by weight.

The combustion turbines operate during peak electricity demand and therefore have low capacity factors. The combustion turbines are also subject to the requirements of 40 CFR 60 Subpart GG.

The facility is a major source of HAPs. The CTs are not subject to the requirements of 40 CFR Part 63, Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines since they were constructed prior to March 5, 2004.

**Compliance Status**

On February 5, 2013 conducted NO\textsubscript{X} LME Emission rate test on No. 2 fuel oil for H CT-2. The testing established the new rate: Base Load H CT-1 NO\textsubscript{X} rate: 0.16 lb/mmBtu; Peak Load H CT-1 NO\textsubscript{X} rate: 0.185 lb/mmBtu, Average water/fuel ratio: 0.94. Dickerson chose LME monitoring methodology as defined in 40 CFR 75.19 to comply with Acid Rain and MDE trading program requirements. As required in 40 CFR 75.19, a new fuel and unit specific NO\textsubscript{X} emission rate is required every 5 years.

The Dickerson 2013 ECR shows the following:

- SO\textsubscript{X} emissions – HCT1: 0.2 tons; HCT2: 0.1tons
- CO emissions – HCT1: 14.3 tons; HCT2: 6.9 tons
- VOC emissions – HCT1: 0.32 tons; HCT2: 0.15 tons
- PM total emissions – HCT1: 4.7 tons; HCT2: 2.2 tons
- NO\textsubscript{X} emissions – HCT1: 32.6 tons; HCT2: 16.3 tons.

The capacity factor was less than 15% for January 1, 2014 thru October 23, 2014. HCT1 operated 110 hours and HCT2 operated 96 hours in 2013.
Applicable Standards and limits
A. Control of Visible Emissions

COMAR 26.11.09.05A(2) & (3) – Fuel Burning Equipment

“Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity”.

Exceptions. Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:
(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period.”

Compliance Demonstration

The Permittee shall verify that there are no visible emissions when burning No.2 fuel oil. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period at least once every 168 hours of operation on oil or at a minimum once per calendar year.

The Permittee shall perform the following, if emissions are visible to human observer:
(a) inspect combustion control system and combustion turbine operations,
(b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and
(c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine.

(d) after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform a Method 9 observation once daily when combustion turbine is operating for 18 minutes until corrective action have eliminated visible emissions.

The requirement for the observation is waived if no fuel oil is burned in the combustion turbines during a calendar year.

The Permittee shall maintain a copy of the visible emissions observations on site for at least five years and make available to the Department upon request.

The Permittee shall report incidents of visible emissions in accordance with permit condition 4, Section III, Plant Wide Conditions, “Report of Excess Emissions and Deviations”. [Reference: COMAR 26.11.03.06C]

Rationale for Periodic Monitoring:

Combustion turbines when burning natural gas or No. 2 fuel oil rarely have visible emissions if properly operated and maintained. The turbines only operate a couple thousand hours per year and the majority of time on natural gas. Little
maintenance is required and there is more than sufficient time to perform maintenance.

B. Control of Sulfur Oxides
1. PSD Approval
CPCN Order No. 68851 Case No. 8063 condition 27 which limits sulfur in fuel content to no more than 0.3% sulfur, by weight.

CPCN Order No. 68851 Case No. 8063 conditions 17 and 18 which limits sulfur emissions to 34 pounds per hour per combustion turbine when firing natural gas and 579 pounds per hour when firing distillate fuel oil. Total annual emissions of SO$_2$ from the two turbines are limited to 1249 tons in any consecutive 12-month period.

Compliance Demonstration
The Permittee shall comply with the monitoring requirements of New Source Performance Standards (NSPS), Subpart GG, 40, CFR 60.334. [Reference: CPCN Order No. 68851 Case No. 8063 condition 16]
The Permittee shall submit quarterly reports to the Department and the Public Service Commission that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, average and maximum sulfur contents of the fuel oil, average and maximum nitrogen contents of the fuel oil, average sulfur content of the natural gas, total calculated SO$_X$ (expresses as SO$_2$) emissions and total calculated NO$_X$ emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department. [Reference: CPCN Order No. 68851 Case No. 8063 condition 28] Note: The Part 70 general record keeping requirements requires records to be maintained for 5 years.

2. NSPS Subpart GG
40 CFR §60.333 which limits sulfur in fuel content to 0.8%.

Compliance Demonstration
40 CFR 60.334:
(h)(1) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D5504-01, D6228-98, or
Gas Processors Association Standard 2377-86 (all of which are incorporated by reference- see §60.17), which measure the major sulfur compounds may be used”;

(h)(3) “Notwithstanding the provisions of paragraph (h) (1) of this section, the owner or operator may elect not to monitor the sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to part 75 of this chapter is required.”

(h)(4) “For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule”.

(i) “The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:”

(1) “Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit’s storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day”.

40 CFR 60.7(f):

“(f)Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection.”
The Permittee shall comply with the record keeping monitoring requirements of New Source Performance Standards (NSPS), Subpart A, 40 CFR 60.7(f).

[Reference: CPCN Order No. 68851 Case No. 8063 condition 16]

40 CFR 60.334(j)- For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) (Nitrogen oxides requirement)

(2) Sulfur dioxide.

(i) “For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit’s storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.”

(iii) “A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample”.

§60.7(c) - “Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.”
3. Acid Rain Permit
The Permittee shall comply with the requirements of the renewal Phase II Acid Rain Permit issued in conjunction with this Part 70 permit. The Acid Rain Permit is attached to the permit in Appendix A.

The Phase II Acid Rain permit requires the Permittee to limit the actual emissions of sulfur dioxide to the number of allowances that the Permittee holds in its account with the Environmental Protection Agency's Clean Air Markets Program at the end of each calendar year. GenOn is given 1082 allowances annually for H CT-1 and 1082 allowances annually for H CT-2. An allowance is one ton of sulfur dioxide emissions. The Permittee is allowed to purchase additional allowances to cover any actual emissions in excess of the annual allowances granted the units. The Permittee is required to submit all the emissions data collected from the CEM systems to the EPA Clean Air Markets Program.

Compliance Demonstration
The Permittee shall continuously monitor sulfur dioxide emissions that meet the requirements of 40 CFR Part 75, subpart B §75.10A(1). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with the Acid Rain Program and the Clean Air Interstate Rule. See the recordkeeping and reporting requirements for 40 CFR Part 75- Acid Rain Program. [Reference: Acid Rain Permit, 40 CFR 75 subpart F & G]

4. Cross-State Air Pollution Rule
TR SO₂ Group 1 Trading Program 40 CFR Part 97 Subpart CCCCCC
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635

Note: §97.606(c) SO₂ emissions requirements. For TR SO₂ Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all TR SO₂ Group 1 units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO₂ Group 1 allowance transfer must be submitted for recordation in a TR SO₂ Group 1 source's compliance account in order to be
available for use in complying with the source’s TR SO₂ Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624.

Compliance Demonstration
The Permittee shall comply with the monitoring, recordkeeping and reporting requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633.

C. Control of Nitrogen Oxides
1. NOₓ RACT

COMAR 26.11.09.08G. - Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 Percent or Less, and Combustion Turbines with a Capacity Factor Greater than 15 Percent.

“(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) Not applicable and
(e) Not applicable.

(2) A person who owns or operates a combustion turbine with a capacity factor greater than 15 percent shall meet an hourly average NOₓ emission rate of not more than 42 ppm when burning gas or 65 ppm when burning oil (dry volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive.”

Compliance Demonstration
If the gas turbine operates more than 500 hours during a calendar year, the Permittee shall perform a combustion analysis and optimize combustion at least once annually. [Reference: COMAR 26.11.09.08G(1)(b)]
The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. The Permittee shall maintain records if the calculations of the capacity factors. [Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]
The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with the support documentation in the Annual Emission Certification Report. [Reference: COMAR 26.11.09.08G(1)(a) COMAR 26.11.03.06C].
2. PSD Limitation

**CPCN Order No. 68851 Case No. 8063 condition 15** which limits NO\textsubscript{X} emissions to no more than 42 parts per million dry (ppmvd) at 15 percent O\textsubscript{2} when firing natural gas. When firing No. 2 fuel oil, emissions, in ppmvd at 15 percent O\textsubscript{2} will be limited to no more than:

- \(57\) for \(N \leq 0.015\)
- \(57 + 400N\) for \(N > 0.015\)

where \(N\) is the nitrogen content of the fuel in percent by weight.

**CPCN Order No. 68851 Case No. 8063 condition 17 and 18** which limits NO\textsubscript{X} emissions from each combustion turbine to 321 pounds per hour when firing natural gas and 608 pounds per hour when firing distillate fuel oil. Total annual emissions of NO\textsubscript{X} from the two turbines are limited to 1311 tons per consecutive 12-month period.

**CPCN Order No. 68851 Case No. 8063 condition 26** which limits the annual average nitrogen content of the fuel oil burned in the combustion turbines to not more than 0.05%, by weight.

**Compliance Demonstration**

The Permittee shall maintain records of test results, analyses of nitrogen content of the fuel and the water to fuel ratio.

[Reference: CPCN Order No. 68851 Case No. 8063]

In addition to NSPS requirements, the Permittee shall also report quarterly, to the Department, any one-hour period during which the average water-to-fuel ratio fell below the water-to-fuel ratio used to demonstrate compliance with the NO\textsubscript{X} emission concentration limit. [Reference: CPCN Order 68851 Case 8063 condition 16]

The Permittee shall submit quarterly reports to the Department that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, average and maximum nitrogen contents of the fuel oil, and total calculated NO\textsubscript{X} emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department. [Reference: CPCN Order No. 68851 Case No. 8063 condition 28]
3. NSPS Subpart GG

40 CFR §60.332 - Standard for nitrogen oxides.

“No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

\[
STD = (0.0075 \times (14.4/Y)) + F
\]

Where:

STD = allowable NO\textsubscript{X} emissions (percent by volume at 15 percent oxygen and on a dry basis)

\( Y \) = manufacturer’s rated heat rate at manufacturer’s rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of \( Y \) shall not exceed 14.4 kilojoules per watt hour.

\( F \) = NO\textsubscript{X} emission allowance for fuel-bound nitrogen as defined in 40 CFR §60.332(a)(3):

<table>
<thead>
<tr>
<th>Fuel-Bound Nitrogen (percent by weight)</th>
<th>F (NO\textsubscript{X} percent by volume)</th>
</tr>
</thead>
<tbody>
<tr>
<td>( N &lt; 0.015 )</td>
<td>0</td>
</tr>
<tr>
<td>( 0.015 &lt; N &lt; 0.1 )</td>
<td>0.04( (N) )</td>
</tr>
<tr>
<td>( 0.1 &lt; N &lt; 0.25 )</td>
<td>0.004 + 0.0067( (N - 0.1) )</td>
</tr>
<tr>
<td>( N &gt; 0.25 )</td>
<td>0.005&quot;</td>
</tr>
</tbody>
</table>

**Compliance Demonstration**

For oil firing

40 CFR 60.334:

(a) “Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO\textsubscript{X} emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine”.

For natural gas firing with dry low NO\textsubscript{X} burners

40 CFR 60.334:

(c) If the owner or operator has previously received State approval of a procedure for monitoring compliance with the applicable NO\textsubscript{X} emission limit under Sec. 332 that approved method may continue to be used. The Permittee shall monitor NO\textsubscript{X} emission rate using methodology in appendix E to 40 CFR 75. The parametric monitoring described in section 2.3 of appendix E shall be followed. The Permittee shall keep on-site a quality-assurance plan, as described in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR 75.
40 CFR 60.7(f):
“(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection.

40 CFR 60.334:
(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:
(A) An excess emissions shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.
(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.
(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owner or operators that elect to monitor combustion parameters or parameters that document proper operation of the NOX emissions controls:
(A) An excess emission shall be a 4-hour rolling unit operating hour in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.
(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.
§60.7(c) - “Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.”

4. Acid Rain Permit
These units are not subject to a NO\textsubscript{X} limitation under Acid Rain because they are not coal-fired. However, the Permittee is required to comply with the continuous NO\textsubscript{X} monitoring requirement of 40CFR Part 75 and associated record keeping and reporting requirements. [Reference: Acid Rain Permit, 40 CFR 75 subpart G]

Compliance Demonstration
See the requirements for the continuous monitoring for NO\textsubscript{X} for 40 CFR Part 75 - Acid Rain Program. [Reference: Acid Rain Permit, 40 CFR 75 subpart B and Appendix E]

See the recordkeeping and reporting requirements for 40 CFR Part 75- Acid Rain Program. [Reference: Acid Rain Permit, 40 CFR 75 subpart F & G]

5. Cross-State Air Pollution Rule
TR NO\textsubscript{X} Annual Trading Program 40 CFR Part 97 Subpart AAAAA
The Permittee shall comply with the provisions and requirements of §97.401 through §97.435

**Note: §97.406(c) NO\(_X\) emissions requirements.** For TR NO\(_X\) Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\(_X\) Annual source and each TR NO\(_X\) Annual unit at the source shall hold, in the source's compliance account, TR NO\(_X\) Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NO\(_X\) emissions for such control period from all TR NO\(_X\) Annual units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\(_X\) Annual allowance transfer must be submitted for recordation in a TR NO\(_X\) Annual source's compliance account in order to be available for use in complying with the source's TR NO\(_X\) Annual emissions limitation for such control period in accordance with §§97.406 and 97.424.

**TR NO\(_X\) Ozone Season Trading Program 40 CFR Part 97 Subpart BBBBB**

The Permittee shall comply with the provisions and requirements of §97.501 through §97.535

**Note: §97.506(c) NO\(_X\) emissions requirements.** For TR NO\(_X\) Ozone Season emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO\(_X\) Ozone Season source and each TR NO\(_X\) Ozone Season unit at the source shall hold, in the source's compliance account, TR NO\(_X\) Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NO\(_X\) emissions for such control period from all TR NO\(_X\) Ozone Season units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\(_X\) Ozone Season allowance transfer must be submitted for recordation in a TR NO\(_X\) Ozone Season source's compliance account in order to be available for use in complying with the source's TR NO\(_X\) Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524.

**Compliance Demonstration**
The Permittee shall comply with the monitoring, recordkeeping and reporting requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the NO\(_X\) Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NO\(_X\) Ozone Season Trading Program.
D. Control of Carbon Monoxide

PSD Approval

**CPCN Order No. 68851 Case No. 8063 conditions 17 and 18** which limits carbon monoxide emissions to 90 pounds per hour per combustion turbine when firing natural gas and 91 pounds per hour when firing distillate fuel oil. Total annual emissions of carbon monoxide from the two turbines are limited to 263 tons per consecutive 12-month period.

**Compliance Demonstration**

The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]**

*Rationale for Periodic Monitoring:*

The PSD limitations for carbon monoxide were based on the design of the turbines. If the Permittee performs preventive maintenance that relates to combustion performance, the Permittee will comply with the carbon monoxide limitations.

E. Control of VOC

**CPCN Order No. 68851 Case No. 8063 conditions 17 and 18** which limits VOC emissions to 2 pounds per hour per combustion turbine when firing natural gas and 4 pounds per hour when firing distillate fuel oil. Total annual emissions of VOC from the two turbines are limited to 9.2 tons per consecutive 12-month period.

**Compliance Demonstration**

The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]**
Rationale for Periodic Monitoring:
The limitations for volatile organic compounds were based on the design of the turbines. If the Permittee performs preventive maintenance that relates to combustion performance, the Permittee will comply with the VOC limitations.

F. Control of Particulate Matter
PSD Approval
CPCN Order No. 68851 Case No. 8063 conditions 17 and 18 which limits PM$_{10}$ and total particulates emissions 21 pounds per hour per combustion turbine when firing natural gas and 27 pounds per hour when firing distillate fuel oil. Total annual emissions of particulates from the two turbines are limited to 60 tons per consecutive 12-month period.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. [Reference: COMAR 26.11.03.06C]

Rationale for Periodic Monitoring:
The PSD limitations for particulate matter were based on the design of the turbines. If the Permittee performs preventive maintenance that relates to combustion performance, the Permittee will comply with the PM limitations.

G. Operating Limitation on Fuel Use
The combustion turbines shall generate electricity using natural gas only. This requirement shall not apply during those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract during maintenance and repair. At such times, the unit shall use No. 2 oil only. Natural gas service curtailments or interruptions shall be verified by a letter each year from the unit’s natural gas supplier identifying the dates on which gas service was restricted. [Reference: CPCN Order #68851 Case No. 8063]

Compliance Demonstration
The Permittee shall maintain records to support the basis for burning fuel oil, either those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 oil by 15 percent or during those times
when the natural gas supply to the unit is curtailed or interrupted under the delivery contract during maintenance and repair.  
[Reference: CPCN Order #68851 Case No. 8063 & COMAR 26.11.03.06C]  
Natural gas service curtailments shall be verified by a letter each year from the unit’s natural gas supplier identifying the dates on which gas service was restricted. [Reference: CPCN Order #68851 Case No. 8063]

Note: The Department, in a February 2, 2006 letter to GenOn, concurred with GenOn’s proposal to clarify natural gas curtailments as follows:

- Gas pipeline is out of service for maintenance or repair. Documentation of these events will be obtained through postings on the gas supplier’s web site;
- Gas supply is interrupted under the delivery contract. Documentation of these events will be obtained through postings on the gas supplier’s web site;
- One or more of the CT Units is called for by PJM to start or extend operation during periods of time when the pipeline operator is not open for business, typically between 6:00 PM and 10:00 AM daily. GenOn will document PJM dispatch notices during these occasions and will purchase gas upon opening of the commercial gas trading market- typically, 10:00 AM, provided the price of delivered gas is not 15% or more of the price of delivered oil.

The 15% cost differential between natural gas and #2 fuel oil will be determined on the following basis:

Daily publications from the Platts service will be utilized as representative industry benchmarks of natural gas and #2 oil pricing. GenOn will document delivered gas-to-oil cost differential using these benchmarks. The delivered cost of #2 oil for GenOn facilities is calculated by taking the Platts Oilgram New York Harbor Barge price and adding $0.0564/gallon in delivery charges. The delivered cost of natural gas for GenOn facilities is calculated by taking the Platts Gas Daily Transco Zone 6 Non-New York price and adding $0.10/MMBtu for delivery and $0.22/MMBtu in Park and Loan fees. The delivered prices for #2 oil and natural gas are calculated on a daily basis to determine if the 15% cost differential is met for the current day unit dispatch.

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**Emissions Unit Number(s): Ash and Coal handling operations**

Ash and coal handling operations.

**Applicable Standards and limits**

Control of Particulate Matter

**COMAR 26.11.06.03C - Particulate Matter from Unconfined Sources.**

“(1) A person may not cause or permit emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, when
appropriate as determined by the Department, the installation and use of hoods, fans, and dust collectors to enclose, capture, and vent emissions. In making this determination, the Department shall consider technological feasibility, practicality, economic impact, and the environmental consequences of the decision.”

**COMAR 26.11.06.03D.** - *Particulate Matter from Materials Handling and Construction.* “A person may not cause or permit any material to be handled, transported, or stored, or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer:

1. Use of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land.
2. Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can create airborne dusts.
3. Installation and use of hoods, fans, and dust collectors to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting of buildings or other similar operations.
4. Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution. Alternate means may be employed to achieve the same results as would covering the vehicles.
5. The paving of roadways and their maintenance in clean condition.
6. The prompt removal from paved streets of earth or other material which has been transported there by trucks or earth moving equipment or erosion by water.”

**Compliance Demonstration**

The Permittee shall prepare and maintain a best management practices (BMPs) plan that contains an explanation of the reasonable precautions that will be used to prevent particulate matter from becoming airborne. The Permittee shall keep the results of the monthly inspections for a period of five (5) years. The Permittee shall maintain the best management practices (BMPs) plan at the facility.

The Permittee shall perform a walk through inspection of the facility to look for fugitive emissions, to verify that reasonable precautions are being implemented and to determine whether the reasonable precautions need to be revised. The inspection shall be conducted at a minimum of once per month at times when the effectiveness of the reasonable precautions can be assessed. [Reference: COMAR 26.11.03.06C].
COMPLIANCE SCHEDULE

GenOn Dickerson Generating Station is currently in compliance with all applicable air quality regulations.

TITLE IV – ACID RAIN

GenOn Dickerson Generating Station is subject to the Acid Rain Program requirements. The Phase II Acid Rain Permit renewal will be issued in conjunction with this Part 70 permit.

TITLE VI – OZONE DEPLETING SUBSTANCES

GenOn Dickerson Generating Station shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F.

SECTION 112(r) – ACCIDENTAL RELEASE

GenOn Dickerson Generating Station is not subject to the requirements of Section 112(r).

PERMIT SHIELD

The GenOn Dickerson Generating Station facility requested that a permit shield be expressly included in the Permittee’s Part 70 permit. Permit shields are granted on an emission unit by emission unit basis. If an emission unit is covered by a permit shield, a permit shield statement will follow the emission unit table in Section IV - Plant Specific Conditions of the permit. In this case, a permit shield was granted for each emission unit covered by the permit.

INSIGNIFICANT ACTIVITIES

This section provides a list of insignificant emissions units that were reported in the Title V permit application. The applicable Clean Air Act requirements, if any, are listed below the insignificant activity.

(1) No. 6 Stationary internal combustion engines with an output less than 500 brake horsepower (373 kilowatts) and which are not used to generate electricity for sale or for peak or load shaving;
These affected units are subject to the following requirements:

(A) COMAR 26.11.09.05E(2), Emissions During Idle Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity.

(B) COMAR 26.11.09.05E(3), Emissions During Operating Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

(C) Exceptions:

(i) COMAR 26.11.09.05E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

(ii) COMAR 26.11.09.05E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:

(a) Engines that are idled continuously when not in service: 30 minutes
(b) all other engines: 15 minutes.

(iii) COMAR 26.11.09.05E(2) & (3) do not apply while maintenance, repair or testing is being performed by qualified mechanics.

(D) COMAR 26.11.09.07A(2)(b), which establishes that the Permittee may not burn, sell, or make available for sale any distillate fuel with a sulfur content by weight in excess of 0.3 percent.

(E) COMAR 26.11.36.03A(1), which establishes that the Permittee may not operate an emergency generator except for emergencies, testing and maintenance purposes.

(F) COMAR 26.11.36.03A(5), which establishes that the Permittee may not operate an emergency generator for testing and engine maintenance purposes between 12:01
a.m. and 2:00 p.m. on any day on which the Department forecasts that the air quality will be a code orange, code red, or code purple unless the engine fails a test and engine maintenance and a re-test are necessary.

(2) Space heaters utilizing direct heat transfer and used solely for comfort heat;

(3) No. 50 Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

These affected units are subject to COMAR 26.11.19.09D, which requires that the Permittee control emissions of volatile organic compounds (VOC) from cold degreasing operations by meeting the following requirements:

(a) COMAR 26.11.19.09D(2)(b), which establishes that the Permittee shall not use any VOC degreasing material that exceeds a vapor pressure of 1 mm Hg at 20 °C;

(b) COMAR 26.11.19.09D(3)(a—d), which requires that the Permittee implement good operating practices designed to minimize spills and evaporation of VOC degreasing material. These practices, which shall be established in writing and displayed such that they are clearly visible to operators, shall include covers (including water covers), lids, or other methods of minimizing evaporative losses, and reducing the time and frequency during which parts are cleaned;

(c) COMAR 26.11.19.09D(4), which prohibits the use of any halogenated VOC for cold degreasing.

The Permittee shall maintain on site for at least five (5) years, and shall make available to the Department upon request, the following records of operating data:

(a) Monthly records of the total VOC degreasing materials used; and

(b) Written descriptions of good operating practices designed to minimize spills and evaporation of VOC degreasing materials.
(4)  ✓  Equipment for drilling, carving, cutting, routing, turning, sawing, planing, spindle sanding, or disc sanding of wood or wood products;

(5)  ✓  Brazing, soldering, or welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals and not directly related to plant maintenance, upkeep and repair or maintenance shop activities;

(6)  Containers, reservoirs, or tanks used exclusively for:

   (a)  ✓  Storage of butane, propane, or liquefied petroleum, or natural gas;

   (b) No. 75  Storage of lubricating oils;

   (c) No. 6  Storage of Numbers 1, 2, 4, 5, and 6 fuel oil and aviation jet engine fuel;

   (d) No. 1  Storage of motor vehicle gasoline and having individual tank capacities of 2,000 gallons (7.6 cubic meters) or less;

   (e) No. 50  The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(7)  ✓  First aid and emergency medical care provided at the facility, including related activities such as sterilization and medicine preparation used in support of a manufacturing or production process;

(8)  ✓  Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

(9)  ✓  Potable water treatment equipment, not including air stripping equipment;
(10) ✔ Comfort air conditioning subject to requirements of Title VI of the Clean Air Act;

(11) ✔ Natural draft hoods or natural draft ventilators that exhaust air pollutants into the ambient air from manufacturing/industrial or commercial processes;

(12) ✔ Laboratory fume hoods and vents;

STATE ONLY ENFORCEABLE REQUIREMENTS

This section of the permit contain state-only enforceable requirements. The requirements in this section will not be enforced by the U.S. Environmental Protection Agency. The requirements in this section are not subject to COMAR 26.11.03 10 - Public Petitions for Review to EPA Regarding Part 70 Permits.

1. Applicable Regulations:

COMAR 26.11.06.08 – Nuisance. “An installation or premises may not be operated or maintained in such a manner that a nuisance or air pollution is created. Nothing in this regulation relating to the control of emissions may in any manner be construed as authorizing or permitting the creation of, or maintenance of, nuisance or air pollution.”

COMAR 26.11.06.09 - Odors. “A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created.”

Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LN Bs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003)

For By-Pass Stack:

Applicable Standards/Limits:

COMAR 26.11.09.05. – Visible Emissions.
“A. Fuel Burning Equipment.
(4) Fuel Burning Equipment Required to Operate a COM. The owner or operator of fuel burning equipment that is subject to the requirement to install and operate a COM shall demonstrate compliance with the applicable visible emissions limitation specified in §A(1) and (2) of this regulation as follows:

(a) For units with a capacity factor greater than 25 percent, until December 31, 2009, compliance is achieved if visible emissions do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4 percent of the unit's operating time in any calendar quarter, during which time visible emissions:

(i) Do not exceed 40.0 percent opacity, except for 5.0 hours or 0.5 percent of the unit's operating time, whichever is greater;
(ii) Do not exceed 70.0 percent opacity for more than four (4) 6-minute periods, except that coal-fired units equipped with electrostatic precipitators may exceed 70.0 percent opacity for no more than 2.2 hours; and
(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two (2) six-minute periods;

(b) For units with a capacity factor greater than 25 percent, beginning January 1, 2010, compliance is achieved if visible emissions do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 2 percent of the unit's operating time in any calendar quarter, during which time visible emissions:

(i) Do not exceed 40.0 percent opacity, except for 5.0 hours or 0.5 percent of the unit's operating time, whichever is greater;
(ii) Do not exceed 70.0 percent opacity for more than four (4) six-minute periods, except that coal-fired units equipped with electrostatic precipitators may exceed 70.0 percent opacity for no more than 2.2 hours; and
(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two (2) six-minute periods;

(c) For units with a capacity factor equal to or less than 25 percent that operate more than 300 hours per quarter, beginning July 1, 2009, compliance with the applicable visible emissions limitation in §A(1) and (2) of this regulation is achieved if, during a calendar quarter, visible emissions do not exceed the applicable standard for more than 20.0 hours, during which time visible emissions:

(i) Do not exceed 40.0 percent opacity for more than 2.2 hours;
(ii) Do not exceed 70 percent for more than four 6-minute periods; and
(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which
time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two 6-minute periods; and
(d) For units with a capacity factor equal to or less than 25 percent that operate 300 hours or less per quarter, beginning July 1, 2009, compliance with the applicable visible emissions limitation in §A(1) and (2) of this regulation is achieved if, during a calendar quarter, visible emissions do not exceed the applicable standard for more than 12.0 hours, during which time visible emissions:
(i) Do not exceed 40.0 percent opacity for more than 2.2 hours;
(ii) Do not exceed 70.0 percent opacity for more than four 6-minute periods; and
(iii) On any calendar day, do not exceed the applicable visible emissions limitation in §A(1) and (2) of this regulation for more than 4.1 hours, during which time visible emissions do not exceed 40.0 percent opacity for more than 1.4 hours and do not exceed 70.0 percent opacity for more than two 6-minute periods.
(5) Notwithstanding the requirements in §A(4) of this regulation, the Department may determine compliance and noncompliance with the visible emissions limitations specified in §A(1) and (2) of this regulation by performing EPA reference Method 9 observations.
(6) In no instance shall excess emissions exempted under this regulation cause or contribute to a violation of any ambient air quality standard in 40 CFR Part 50, as amended, or any applicable requirements of 40 CFR Part 60, 61, or 63, as amended.

“B. Determining Violations.
(1) For each unit required to operate a COM pursuant to COMAR 26.11.01.10A(1)(a) and (b), each day during a calendar quarter when the opacity of emissions from that unit during the calendar quarter or calendar day, as applicable, exceeds the emission limitations in §A(4)(a), (b), (c) and (d) of this regulation shall constitute a separate day of violation.
(2) A violation of §A(4)(a)(i), (ii), or (iii), §A(4)(b)(i), (ii) or (iii), §A(4)(c)(i), (ii) or (iii), or §A(4)(d)(i), (ii) or (iii), of this regulation, as applicable, that occur on the same day shall constitute separate violations.
(3) A daily violation that occurs during the same calendar quarter as a quarterly violation is a separate violation.

“C. Fuel Burning Equipment Subject to Federal COM Requirements. Except for owners or operators of fuel burning equipment subject to any federal requirement that mandates operation of a COM and as provided in §D of this regulation, the owner or operator of fuel burning equipment required to install and operate a COM may discontinue the operation of the COM on fuel burning equipment that is served by a flue gas desulfurization device:
(1) When emissions from the equipment do not bypass the flue gas
desulfurization device serving the equipment;
(2) When the flue gas desulfurization device serving the equipment is in
operation;
(3) If the owner or operator has demonstrated to the Department's satisfaction, in
accordance with 40 CFR §75.14, as amended, and all other applicable State and
federal requirements, that water vapor is present in the flue gas from the
equipment and would impede the accuracy of opacity measurements; and
(4) If the owner or operator has fully implemented an alternative plan, approved
by the Department, for monitoring opacity levels and particulate matter emissions
from the stack that includes:
(a) A schedule for monthly observations of visible emissions from the stack by a
person trained to perform Method 9 observations; and
(b) Installation and operation of a particulate matter CEM that complies with all
applicable State and federal requirements for particulate matter CEMs. “

“D. If, for units equipped with a flue gas desulfurization device, emissions bypass
the device and are discharged through a bypass stack, the bypass stack shall be
equipped with a COM approved by the Department.”

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<th>March 2008 Opacity Consent Decree</th>
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<td><strong>Emissions Unit Number(s):</strong> D-1, D-2, &amp; D-3: Boilers Cont’d</td>
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**March 2008 Opacity Consent Decree**

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum,
bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel
oil is used for ignition, warm-up and flame stabilization. The boilers are equipped
with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a
common FGD system. (3-0001, 3-0002, & 3-0003)

**Applicable Requirements:**

**Control of Visible Emissions**

*Completed: Consent Decree Section V. Evaluation of Opacity Exceedances,
paragraphs 7, 8, 9, 10.*

**Compliance Assurance Monitoring**

*Completed: Consent Decree Section VII. Implementation of Interim and Final
CAM Plans, paragraphs 19, 20, 21, 22, 23, 24, 25.*

**Particulate Matter Stack Testing**

*Completed: Consent Decree Section VIII. Particulate Matter Stack Testing,*
<table>
<thead>
<tr>
<th>Paragraphs</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>26, 27, 28</td>
<td>See letter dated October 6, 2011 – Petition to stop 170-day stack testing.</td>
</tr>
</tbody>
</table>

**Improvements to the Dickerson Baghouse**

*Completed.* Consent Decree Section IX: Improvements to the Dickerson Baghouse, paragraphs 29, 30

17. GenOn shall use reasonable efforts to keep each PM CEMS operating and producing data whenever a Unit served by the PM CEMS is operating. **[Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 31, 32.]**

18. **Completed.** **[Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 34.]**

19. GenOn shall provide the Department with written notice of the date on which initial operation of each PM CEMS is commenced. No later than 90 days following initial operation of a PM CEMS, GenOn shall submit to the Department for review and approval a proposed Quality/Assurance/Quality Control (“QA/QC”) protocol for that PM CEMS, including a maintenance schedule, which shall be followed in calibrating and operating the PM CEMS. The protocol shall be developed in accordance with EPA Procedures 2 of Appendix F or 40 CFR Part 60 (“Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems Used at Stationary Sources”). GenOn shall operate each PM CEMS in accordance with the approved protocol. **[Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 35]**

20. GenOn shall submit quarterly PM CEMS reports to the Department that comply with COMAR 26.11.01.11E(2)(c). All data shall be reported in 24-hour rolling averages. **[Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 36]**


22. PM CEMS data shall not be used to demonstrate compliance with the applicable particulate matter emission limitation until the 181st day following installation of the PM CEMS on that Unit, except with regard to Morgantown Units 1 and 2, as to which the provisions of Paragraph 41 shall govern the 90-day period subsequent to the 180 day following the installation of the PM CEMS.
NRG Energy, Inc, Dickerson Generating Station  
21200 Martinsburg Road, Dickerson, Maryland 20842  
Part 70 Operating Permit No. 24-031-0019  
Permit Fact Sheet

March 2008 Opacity Consent Decree
Commencing on the 181st day following installation of the PM CEMs, CEMs data may be used to demonstrate compliance with applicable particulate matter emission limitations unless GenOn asserts that the continued operation of the PM CEMs is impracticable. In such event, PM CEMs shall not be used to demonstrate compliance with the applicable particulate matter emission limitation unless and until the Department determines that the continued operation of the PM CEMs is not impracticable. Unless, otherwise required by State or federal law or regulation, in demonstrating compliance, particulate emissions during periods of startup and shutdown shall not be included. Periods of startup shall end at such time as the Unit reaches minimum load levels. For Dickerson Units 1, 2 and 3, minimum load is reached when the Unit generates 75 gross megawatts. The Department may approve a longer startup period for a Unit if necessary to ensure that the PM CEMs serving that Unit is accurately recording particulate emissions. Periods of shutdown shall only commence when the Unit ceases burning any amount of coal. GenOn shall maintain a record of the date and time that: (a) startup commenced; (b) minimum load was reached; and (c) combustion of coal ceased. GenOn shall make such records available to the Department upon request. At all times when PM CEMs are used to demonstrate compliance, each PM CEMs shall, at a minimum, obtain valid PM CEMs hourly averages for 75% of all operating hours on a 30-day rolling average. Commencing on January 1, 2012, GenOn shall use all reasonable efforts to obtain valid PM CEMs hourly averages for a minimum of 90% of all operating hours on a 30-day rolling average. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 38]

23. Unless otherwise required by State or federal law or regulation, upon initial operation of an FGD pollution control device on a Unit subject to this Consent Decree, GenOn may discontinue use of opacity CEMs to monitor the opacity emissions from the stack serving such Unit, provided that: (a) emissions from such Unit do not bypass the FGD serving that Unit and FGD technology serving that Unit is in operation; (b) GenOn has fully implemented an alternative plan for monitoring opacity levels and particulate matter emissions from the stack serving such Unit that has been approved by the Department; and (c) GenOn has demonstrated to the satisfaction of the Department and the United States Environmental Protection Agency, in accordance with 40 CFR §75.14 and applicable EPA regulations, policy and guidelines, that condensed water is present in the flue gas stream from such Unit and would impede the accuracy of opacity measurements. [Reference: Consent Decree Section X: Installation of Particulate Matter CEMS, paragraph 39]

Mist Eliminators
24. GenOn shall install and maintain a mist eliminator in each FGD/SO₂ absorber for Dickerson Units 1, 2 and 3, as specified in each of GenOn’s separate
March 2008 Opacity Consent Decree

applications for a CPCN to install FGD technology at the Plants. [Reference: Consent Decree Section XIII. Mist Eliminators, paragraph 44] Completed.

Reporting Requirements

25. Beginning with the quarter that commences on January 1, 2008, GenOn shall submit to the Department quarterly reports describing the status of GenOn’s compliance with the terms and conditions of the Consent Decree. Each quarterly report shall be due no later than 30 days following the end of the quarter, unless such date falls on a weekend or holiday, in which case the report shall be due on the next business day. The first quarterly report shall be due on April 30, 2008. [Reference: Consent Decree Section XIV. Reporting, paragraph 45]

26. Past. Completed. [Reference: Consent Decree Section XIV. Reporting, paragraph 46]

Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d

Alternate Operating Scenario for Emission Units D-1, D-2 and D-3

The Permittee shall burn used oil and boiler chemical cleaning waste materials in the utility boilers.

COMAR 26.11.09.10 - Requirements to Burn Used Oil and Waste Combustible Fluid as Fuel.

Applicable Regulations:

A. “General Requirements.
(1) A person who proposes to burn used oil or waste combustible fluid in an installation shall submit the following information to the Department:
(a) A description of, and the location of, each fuel-burning equipment or other installation in which the used oil or WCF is to be burned and the rated heat input capacity of each;
(b) The type and amount of fuel currently being used in each installation and the gallons of used oil or WCF expected to be burned annually;
(c) The maximum percentage of used oil or WCF to be burned as fuel in each installation; and
(d) An analysis by an independent laboratory of a representative sample of the used oil or WCF, which shall include the concentration of each of the materials listed in §B of this regulation, the PCB concentration, and the flash point.
(2) A person may burn on-specification used oil in any installation upon submitting the information required in §A(1) of this regulation.  
(3) A person who is burning used oil or WCF under a current approval issued by the Department may continue to burn the approved material if:
(a) The person registers the equipment that is burning the used oil or WCF by submitting the information required in §A(1) of this regulation; and
(b) The used oil or WCF is being burned in an authorized installation.  

(4) A person who proposes to burn off-specification used oil or WCF in an installation other than a space heater, as provided in 40 CFR §279.23, is subject to the permit or registration requirements in COMAR 26.11.02.
(5) A person who receives a permit or registration to burn used oil or WCF shall burn only the materials authorized in the permit or registration.
(6) A person may burn off-specification used oil and waste combustible fluid only in those installations listed at 40 CFR §279.12(c).”

B “Specifications for Used Oil.
(1) Except as provided in §B(2) of this regulation, used oil specifications are as follows:
   Material       Allowable Level
   (a) Lead       100 ppm
   (b) Total halogens 4,000 ppm
   (c) Arsenic    5 ppm
   (d) Cadmium    2 ppm
   (e) Chromium   10 ppm
   (f) Flash point 100° F minimum
(2) For used oil that does not satisfy the rebuttable presumption for halogens at 40 CFR 279.10(b)(1)(ii) and 279.63, the maximum allowable level for halogens may not exceed 1,000 ppm.”

Record keeping
The Permittee shall maintain a record of the quantity of used oil that is burned and analyses by an independent laboratory of representative samples of the used oil.

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Healthy Air Act Requirements
These regulations became effective under an Emergency Action on January 18, 2007 and were adopted as permanent regulations on June 17, 2007. They implement the requirements of the Healthy Air Act (Ch. 23, Acts of 2006), which was signed into law on April 6, 2006 and which established emission limitations
and related requirements for NO\textsubscript{X}, SO\textsubscript{2} and mercury. Regulations .01-.03, .03E, .05 and .06, related to the reductions of NO\textsubscript{X} and SO\textsubscript{2} emissions, were submitted to EPA as a revision to Maryland’s State Implementation Plan (SIP) on June 12, 2007. The requirements for NO\textsubscript{X} and SO\textsubscript{2} emissions, all except for one were approved by EPA, as a SIP revision on September 4, 2008 with an effective date of October 6, 2008. The requirements for mercury emissions are not part of the Maryland’s SIP and are therefore, part of the State-Only Section.

Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBS and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003)

Applicable Regulations:

COMAR 26.11.27 - Emission Limitations for Power Plant
COMAR 26.11.27.03 – General Requirements
A. An electric generating unit subject to this chapter shall comply with the emission limitations for NO\textsubscript{X}, SO\textsubscript{2}, and mercury as provided in this regulation.

B. NO\textsubscript{X} Emission Limitations.

Healthy Air Act State-Only enforceable NO\textsubscript{X} requirement
COMAR 26.11.27.03B(7)(iii) – “Not later than December 31 of the year in which the emission limitation is exceeded, the owner or operator of the affected generating unit or units transfers to the Maryland Environmental Surrender Account, ozone season NO\textsubscript{X} allowances equivalent in number to the tons of NO\textsubscript{X} emitted in excess of the emission limitation in §B(4) or (6), as applicable”.

COMAR 26.11.27.03D. Mercury Emission Limitations.
(1) For the 12 months beginning January 1, 2010 and ending with the 12 months beginning December 1, 2012 to December 1, 2013, each affected facility shall meet 12-month rolling average removal efficiency for mercury of at least 80 percent.
(2) For the 12 months beginning January 1, 2013 and thereafter, each affected facility shall meet 12-month rolling average removal efficiency for mercury of at least 90 percent.
(3) The mercury removal efficiency required in §D(1) and (2) of this regulation shall be determined in accordance with Regulation .04 of this chapter.

COMAR 26.11.27.05 - Monitoring and Reporting Requirements.
A. Compliance with the emission limitations in this chapter shall be demonstrated with a continuous emission monitoring system that is installed, operated, and
certified in accordance with 40 CFR Part 75.

**COMAR 26.11.27.05 - Monitoring and Reporting Requirements.**

**B.** Beginning with calendar year 2007 and each year thereafter, the owner or operator of each electric generating unit subject to this chapter shall submit an annual report to the Department, the Department of Natural Resources, and the Public Service Commission. The report for each calendar year shall be submitted not later than March 1 of the following year.

**C.** Each report shall include:

1. Emissions performance results related to compliance with the emission requirements under this chapter;
2. Emissions of NO\textsubscript{X} and SO\textsubscript{2}, and beginning with calendar year 2010, mercury, emitted during the previous calendar year from each affected unit;
3. A current compliance plan; and
4. Any other information requested by the Department.

**Emissions Unit Number(s):** D-1, D-2 and D-3: Boilers Cont’d

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LNBs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. *(3-0001, 3-0002, & 3-0003)*

**Applicable Regulations:**

**Management of Coal Combustion Byproducts**

**COMAR 26.04.10.03 - General Restrictions and Specifically Prohibited Acts.**

1. **COMAR 26.04.10.03B(3) - Air Pollution**

   “(a) A person may not engage in the disposal, storage, transportation, processing, handling, or use of coal combustion byproducts without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall include, when appropriate as determined by the Department, those precautions described in COMAR 26.11.06.03C and D.”

   “(b) In addition to the requirements of paragraph (a), a person may not transport coal combustion byproducts without taking reasonable precautions to prevent particulate matter from becoming airborne. These reasonable precautions shall
include, at a minimum the following:
(i)Vehicles transporting coal combustion byproducts shall be fully enclosed, or fully enclosed on all sides and covered with a firmly secured canvas or similar type covering, so as to prevent any coal combustion byproducts from blowing off, falling off, or spilling out of the vehicle or the coal combustion byproducts shall be handled and transported in sealed containers designed for transportation of powdery solids;
(ii)Before leaving a site where coal combustion byproducts are loaded or off-loaded, vehicles transporting coal combustion byproducts shall be rendered clean and free of excess material or debris that could blow off, fall off, or spill during transport;
(iii)Coal combustion byproducts being loaded into or off-loaded from a vehicle shall be sufficiently moistened or otherwise conditioned or contained to prevent particulate coal combustion byproducts from becoming airborne or causing fugitive air emissions; and
(iv)Transporters of coal combustion byproducts shall maintain an inspection log that shall be maintained in each vehicle at all times during transport of coal combustion byproducts that shall certify compliance with the standards in this regulation .03B(3)(b).”

Emissions Unit Number(s): D-1, D-2 and D-3: Boilers Cont’d

Three (3) Combustion Engineering, Inc tangentially fired, dry bottom, drum, bituminous coal fired boilers, each nominally rated at 191 megawatts. No. 2 fuel oil is used for ignition, warm-up and flame stabilization. The boilers are equipped with LN Bs and SOFA, a SNCR system, an ESP, a common baghouse and a common FGD system. (3-0001, 3-0002, & 3-0003)

COMAR 26.11.38 – Control of NO\textsubscript{X} Emissions from Coal-Fired Electric Generating Units.

Applicable Regulations:

COMAR 26.11.38.02 – Applicability
“The provisions of this chapter apply to an affected electric generating unit as that term is defined in §.01B of this chapter.”

COMAR 26.11.38.03 – NO\textsubscript{X} Emission Control Requirements
A. Daily NO\textsubscript{X} Reduction Requirements During the Ozone Season
   (1) Not later than 45 days after the effective date of this regulation, the owner or operator of an affected electric generating unit shall submit a plan to the
Department and EPA for approval that demonstrated how each affected electric generating unit (“the unit”) will operate installed pollution control technology and combustion controls to meet the requirements of §A(2) of this regulation. The plan shall cover all modes of operation, including but not limited to normal operations, start-up, shut-down and low load operations.

(2) Beginning on May 1, 2015, for each operating day during the ozone season, the owner or operator of an affected electric generating unit shall minimize NO\textsubscript{X} emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers’ specification, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 CFR §60.11(d)) for such equipment and the unit at all times the unit is in operation while burning any coal.

B. Ozone Season NO\textsubscript{X} Reduction Requirements.
   (1) Except as provided in §B(3) of this regulation, the owner or operator of an affected electric generating unit shall not exceed a NO\textsubscript{X} 30-day system-wide rolling average emission rate of 0.15 lbs/MMBtu during the ozone season.
   (2) The owner or operator of an affected electric generating unit subject to the provisions of this regulation shall continue to meet ozone season NO\textsubscript{X} reduction requirements in COMAR 26.11.27.

C. Annual NO\textsubscript{X} Reduction Requirements.
   The owner of operator of an affected electric generating unit subject to the provisions of this regulation shall continue to meet the annual NO\textsubscript{X} reduction requirements in COMAR 26.11.27.

COMAR 26.11.38.04 – Compliance Demonstration Requirements
A. Procedures for demonstrating compliance with §.03(A) of this chapter.
   (1) An affected electric generating unit shall demonstrate, to the Department’s satisfaction, compliance with §.03(A)(2) of this chapter, using the information collected and maintained in accordance with §.03(A)(1) of this chapter and any additional demonstration available to and maintained by the affected electric generating unit.
(2) An affected electric generating unit shall not be required to submit a unit-specific report consistent with §A(3) of this regulation when the unit emits at levels that are at or below the following rates:

<table>
<thead>
<tr>
<th>Affected Unit</th>
<th>24-Hour Block Average NO\textsubscript{X} Emissions in lbs/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dickerson</td>
<td></td>
</tr>
<tr>
<td>Unit 1 only</td>
<td>0.24</td>
</tr>
<tr>
<td>Unit 2 only</td>
<td>0.24</td>
</tr>
<tr>
<td>Unit 3 only</td>
<td>0.24</td>
</tr>
<tr>
<td>Two or more Units combined</td>
<td>0.24</td>
</tr>
</tbody>
</table>

(3) The owner or operator of an affected electric generating unit subject to §.03(A)(2) of this chapter shall submit a unit-specific report for each day the unit exceeds its NO\textsubscript{X} emission rate of §A(2) of this regulation, which shall include the following information for the entire operating day:
(a) Hours of operation for the unit;
(b) Hourly averages of operating temperature of installed pollution control technology;
(c) Hourly averages of heat input (MMBtu/hr);
(d) Hourly averages of output (MWh);
(e) Hourly averages of Ammonia or urea flow rates;
(f) Hourly averages of NO\textsubscript{X} emissions data (lbs/MMBtu and tons);
(g) Malfunction data;
(h) The technical and operational reason the rate was exceeded, such as:
   (i) Operator error;
   (ii) Technical events beyond the control of the operator (e.g. acts of God, malfunction); or
   (iii) Dispatch requirements that mandate unplanned operation (e.g. start-ups and shut-down, idling and operation at low voltage or low load)
   (i) A written narrative describing any actions taken to reduce emission rates; and
   (j) Other information that the Department determines is necessary to evaluate the data or to ensure that compliance is achieved.

(4) An exceedance of the emissions rate if §A(2) of this regulation as a result of factors including but not limited to start-up and shut-down, days when the unit was directed by the electric grid operator to operate at low load or to operated pursuant to any emergency generation operations required by the electric grid operator, including necessary testing for emergency operations, or to have otherwise occurred during operations which are deemed consistent with the unit’s technological limitations, manufacturers’ specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions, shall not be
considered a violation of §.03A(2) of this chapter provided that the provisions of the approved plan as required in §.03A(1) of this chapter are met.

B. Procedures for demonstrating compliance with NO\textsubscript{X} emission rates of this chapter.

(1) Compliance with the NO\textsubscript{X} emission rate limitations in §.03B(1), §.03D(2), and §.04A(2) of this chapter shall be demonstrated with a continuous emission monitoring system that is installed, operated, and certified in accordance with 40 CFR Part 75.

(2) For §.03B(1) of this chapter, in order to calculate the 30-day system-wide rolling average emissions rated, if twenty-nine system operating days are not available from the current ozone season, system operating days from the previous ozone season shall be used.

COMAR 26.11.38.05 – Reporting Requirements

A. Reporting Schedule

(1) Beginning 30 days after the first month of the ozone season following the effective date of this chapter, each affected electric generating unit subject to the requirements of this chapter shall submit a monthly report to the Department detailing the status of compliance with this chapter during the ozone season.

(2) Each subsequent monthly report shall be submitted to the Department not later than 30 days following the end of the calendar month during the ozone season.

B. Monthly Reports During Ozone Season.

Monthly reports during the ozone season shall include:

(1) Daily pass or fail of the NO\textsubscript{X} emission rates of §.04A(2) of this chapter.

(2) The reporting information as required under §.04A(3) of this chapter.

(3) The 30-day system-wide rolling average emissions rate for each affected electric generating unit to demonstrate compliance with §.03B(1) of this chapter.

2. Record Keeping and Reporting:

The Permittee shall submit to the Department, by April 1 of each year during the term of this permit, a written certification of the results of an analysis of emissions of toxic air pollutants from the Permittee’s facility during the previous calendar year. The analysis shall include either:

(a) a statement that previously submitted compliance demonstrations for emissions of toxic air pollutants remain valid; or
(b) a revised compliance demonstration, developed in accordance with requirements included under COMAR 26.11.15 & 16, that accounts for changes in operations, analytical methods, emissions determinations, or other factors that have invalidated previous demonstrations.