KEEP PERMIT AT SITE **CONTROL NO. B - 06224**

State of Maryland

Lawrence J. Hogan, Jr.
Governor

Boyd K. Rutherford
Lt. Governor

Ben Grumbles
Secretary

DEPARTMENT OF THE ENVIRONMENT

Air and Radiation Administration
1800 Washington Boulevard, Suite 720
Baltimore, MD 21230

[ ] Construction Permit [X] Part 70 Operating Permit

PERMIT NO.	24-017-0014	DATE ISSUED	December 1, 2017
PERMIT FEE	To be paid in accordance with COMAR 26.11.02.19B	EXPIRATION DATE	September 30, 2022

LEGAL OWNER & ADDRESS

GenOn Mid-Atlantic, LLC
12620 Crain Hwy.
Newburg, MD 20664
Attention: Mr. Thomas G. Turk, General Mgr.

SITE

Morgantown Generating Station
12620 Crain Hwy.
Newburg, MD 20664
Charles County
AI # 3101

SOURCE DESCRIPTION

A generation and transmission of electric energy for sale facility consisting of two (2) coal firing units, four (4) auxiliary boilers, six (6) combustion turbines and associated equipment.

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

Program Manager

Director, Air and Radiation Administration

MDE/ARMA/PER.009 (REV. 10-08-03) (NOT TRANSFERABLE)

GenOn MID-ATLANTIC, LLC.
MORGANTOWN GENERATING STATION
12620 CRAIN HIGHWAY, NEWBURG, MD 20664
PART 70 OPERATING PERMIT NO. 24-017-0014
RENEWAL 2017

SECTION I SOURCE IDENTIFICATION

1. DESCRIPTION OF FACILITY

Morgantown Generating Station is engaged in the generation of electric energy. The primary SIC code for this plant is 4911. The major components of the facility consist of two (2) steam units primarily firing bituminous coal, four (4) auxiliary boilers firing on No. 2 fuel oil, six (6) combustion turbines firing on No. 2 fuel oil and their associated fuel storage and handling equipment. The gross winter capacity of the facility is 1580 MW.

Each of the two (2) boilers, manufactured by Combustion Engineering (CE), is rated at 640 MW. Each boiler is a tangentially coal fired supercritical unit with a superheater, single reheat and economizer. Units 1 and 2 are each equipped with Low NO_X burners (LNBs), Electrostatic Precipitators (ESP), Selective Catalytic Reduction (SCR), Over Fire Air (OFA) and Flue Gas Desulfurization (FGD) and exhausted through a 400 foot high stack. When the FGD systems are not in use, the flue gas is exhausted through a 700 foot high by-pass stack. The Units also have the capability of firing on No. 6 oil as an alternative primary fuel.

Three (3) auxiliary boilers are CE (Model #30 VP-12W) package boilers each rated at 164 MMBtu/hr and one (1) auxiliary boiler is a CE (Model 30VP2180R/48) rated at 219.3 MMBtu/hr. These auxiliary boilers fire No. 2 oil and are used for start-up steam and space heating.

Combustion Turbines CT-1 and CT-2 are General Electric (GE) Frame-5 rated at 20 MWs each and are fired on No. 2 fuel oil. These CTs are both used for blackstart and peaking purposes. Combustion Turbines CT-3, 4, 5 and 6 are GE Frame -7 each rated at 65 MW and fired on No. 2 fuel oil. These CTs are used for peaking purposes.

A coal barge unloader system, a gypsum barge loading system, a coal blending system and a fly-ash beneficiation facility (STAR) are also located at the station.

2. FACILITY INVENTORY LIST

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
F1	3-0002	Unit 1: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with a LNBs, SCR, FGD and ESP. The unit's exhaust is directed to an individual flue 400 foot stack. When the FGD system is not in service the Unit's exhaust is directed to a 700 foot by-pass stack. The Unit maintains the capability of firing No.6 oil as an alternative primary fuel	June 1970 (Commercial operation date)
F2	3-0003	Unit 2: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with a LNBs, SCR, FGD and ESP. The unit's exhaust is directed to an individual flue 400 foot stack. When the FGD system is not in service the Unit's exhaust is directed to a 700 foot by-pass stack. The Unit maintains the capability of firing No. 6 oil as an alternative primary fuel	June 1971 (Commercial operation date)
F-CT 1	4-0068	General Electric Frame 5 combustion turbine rated at 20 MW and used for black start capability and peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	March 1970
F-CT 2	4-0069	General Electric Frame 5 combustion turbine rated at 20 MW and used for black start capability and peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1971

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
F-CT 3	4-0070	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-CT 4	4-0071	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-CT 5	4-0073	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-CT 6	4-0074	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-Aux 1	4-0015	Auxiliary boiler No. 1 manufactured by CE-Alstom (Model No.30 VP-12W) is used for start-up steam and space heat heating. Auxiliary boiler No. 1 is fired with No. 2 fuel oil and has a maximum rating of 164 mmBtu/hr.	1970
F-Aux 2	4-0191	Auxiliary boiler No. 2 manufactured by CE-Alstom (Model No.30VP21808R/48) is used for start-up steam and space heat heating. Auxiliary boiler No. 2 is fired with No. 2 fuel oil and has a maximum rating of 219.3 mmBtu/hr.	June 2004
F-Aux 3	4-0017	Auxiliary boiler No.3 manufactured by CE-Alstom (Model No.30 VP-12W) is used for start-up steam and space heat heating. Auxiliary boiler No. 3 is fired with No. 2 fuel oil and has a maximum rating of 164 mmBtu/hr.	1970
F-Aux 4	4-0018	Auxiliary boiler No. 4 manufactured by CE-	1970

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
		Alstom (Model No.30 VP-12W) is used for start-up steam and space heat heating. Auxiliary boiler No. 4 is fired with No. 2 fuel oil and has a maximum rating of 164 mmBtu/hr.	
Coal Barge Unloader	6-0138 (CPCN 9031)	The barge loading facility consists of a dock, barge unloader, a transfer and distribution system and a railcar loading facility. The barge unloader system is sized to unload up to 5.0 million tons of coal per year. The barge unloader's transfer and distribution system is integrated into Morgantown's existing coal handling system.	October 2007
Gypsum Barge Loading System	017-0014-6-0153 (CPCN 9148)	The Gypsum Barge Loading System is to convey and load gypsum produced by both the Chalk Point and Morgantown SO_2 FGD systems. The Gypsum Barge Loading System consists of the following subsystems: 1000-tph conveyor system; five transfer towers, one pier tripper conveyor, one telescoping barge load-out conveyor and rail unloading hopper and conveyor for chalk Point gypsum transfer.	October 2007
FGD System	(CPCN 9085)	A wet flue gas desulfurization (FGD) system is installed on both Units 1 and 2. The FGD system controls SO_2 and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing gypsum 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.	December 2009
Coal Blending System	017-0014-6-0154 (CPCN 9148)	The coal blending system is designed to blend various coals with different characteristics to match the specification of the Morgantown's boilers and air quality	March 2010

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
		control equipment. The coal blending system consists of the following subsystems: new stack-out facilities in the south coal yard; underground reclaim facilities in existing south and north coal yards; reclaim transfer point to integrate the reclaim from the north and south coal yards; refurbished and upgraded emergency reclaim; and enclosed transfer station with dust suppression system.	
STAR	6-0150 (CPCN 9229)	The STAR facility processes fly ash in to a Portland cement substitute. The STAR facility is made up of a 140 mmBtu/hr process reactor equipped with a supplemental 65 mmBtu/hr propane heater and a 20 mmBtu/hr propane duct burner. The unit is equipped with a fabric filter baghouse and wet flue gas desulfurization scrubber system. Exhaust gases are directed through a 125 foot stack. The STAR process facility includes a fly ash receiving feed silo and a truck unloading facility, a 30,000 ton product storage dome which includes a product silo with a truck loading facility. The reactor, the storage dome and silos are equipped with pneumatic ash transfer systems.	December 2011

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
ARA	Air and Radiation 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
FGD	Flue Gas Desulfurization
FR	Federal Register
gr	grains
HAP	Hazardous Air Pollutant
MACT	Maximum Achievable Control Technology
MDE	Maryland Department of the Environment
MVAC	Motor Vehicle Air Conditioner
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NO_x	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
PSD	Prevention of Significant Deterioration

PTC	Permit to construct
PTO	Permit to operate (State)
SIC	Standard Industrial Classification
SO_2	Sulfur Dioxide
STAR	Staged Turbulent Air Reactor
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 b y (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

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)]**

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1.0	**Emissions Unit Number(s): F1 and F2: Boilers** **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with LNBs, SCR, ESP and FGD. The unit's exhaust is directed to an individual flue 400 foot stack. When the FGD system is not in service the Unit's exhaust is directed to a 700 foot by-pass stack. The Unit maintains the capability of firing No.6 oil as an alternative primary fuel. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with LNBs, SCR, ESP and FGD. The unit's exhaust is directed to an individual flue 400 foot stack. When the FGD system is not in service the Unit's exhaust is directed to a 700 foot by-pass stack. The Unit maintains the capability of firing No.6 oil as an alternative primary fuel. (**3-0003**)
1.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A (1) & (3)** – Fuel Burning Equipment "Areas I, II, V, and VI. In Areas I, II, V, and VI, a person may not cause or

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	permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is greater than 20 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 Particulate Matter Emissions **COMAR 26.11.09.06A(1)** – Fuel-Burning Equipment Constructed Before January 17, 1972. "A person may not cause or permit particulate matter caused by the combustion of solid fuel or residual fuel oil in the fuel burning equipment erected before January 17, 1972, to be discharged into the atmosphere in excess of the amounts shown in Figure 1." (**Note**: Maximum allowable value in Figure 1 value is 0.14 pounds/million BTU of heat input) **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." **40 CFR Part 63, Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units (MATS rule) -** The Permittee will comply with a PM emissions limit of 0.03 pounds/million Btu of heat input. See the details in the compliance table for the MATS rule **Table IV – 1e – MACT Subpart UUUUU.** C. Control of Sulfur Oxides (1) **COMAR 26.11.09.07A(1)** - 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 I, II, V and VI: (a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour;

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(b) Residual fuel oils, 2.0 percent;
(c) Distillate fuel oils, 0.3 percent;
(d) Process gas used as fuel, 0.3 percent."

See Additional Requirements in Table IV-1e: CPCN 9085.

(2) Emission Limitation for Power Plants requirements*:*
COMAR 26.11.27.03C. SO$_2$ Emission Limitations.
(1) Except as provided in §E of this regulation, annual SO$_2$ emissions from each affected electric generating unit may not exceed the number of tons in §C(2) of this regulation.
(2) Annual Tonnage Limitations.

Affected Unit	Annual SO$_2$ Tonnage Limitations Beginning
	January 1, 2013
Morgantown Unit 1	4,678 tons
Morgantown Unit 2	4,646 tons
System-wide	18,541 tons

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.

(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 SO$_2$ Group 1 Trading Program 40 CFR Part 97 Subpart CCCCC
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635

Table IV – 1	
	Note: §97.606(c) SO_2 emissions requirements. For TR SO_2 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 SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 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 SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624. D. Control of Nitrogen Oxides (1) NO_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_X emission rates in §C(2) of this regulation. (2) The maximum NO_X emission rates as pounds of NO_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

Table IV – 1

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_X CEM or an alternative NO_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_X emissions standards in this regulation using a CEM, compliance shall be determined as 30-day rolling averages."

(2) Emission Limitation for Power Plants requirements:
COMAR 26.11.27.03B. NO_X Emission Limitations.
"(1) Except as provided in §E of this regulation, annual NO_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.

Affected Unit	Annual NO_X Tonnage Limitations Beginning January 1, 2012
Morgantown Unit 1	2,094 tons
Morgantown Unit 2	2,079 tons
System-wide	8,298 tons

(3) Except as provided in §E of this regulation, ozone season NO_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.

Affected Unit	Ozone Season NO_X Tonnage Limitations Beginning May 1, 2012
Morgantown Unit 1	868 tons
Morgantown Unit 2	864 tons
System-wide	3,567 tons

(7) Electric System Reliability During Ozone Seasons.

Table IV – 1	
	(a) An exceedance of the NO_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_X emissions in excess of the emission limitation; and (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_X allowances equivalent in number to the tons of NO_X emitted in excess of the emission limitation in §B(4) or (6), as applicable.. (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**. <u>System-Wide Compliance Determinations</u>. "(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

Table IV – 1	
	regulation applicable to that electric generating unit." (3) Control of NO_X Emissions from Coal-Fired Electric Generating Units **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_X Emission Control Requirements A. Daily NO_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_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_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_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_X reduction requirements in COMAR 26.11.27. C. Annual NO_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_X reduction requirements in COMAR 26.11.27. (4) 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

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	Tonnage Limitation and a System-Wide Ozone Season NO_X Emissions Limitation. Morgantown Units 1 and Unit 2 are included in the GenOn System. See the details of the Potomac River Consent Decree under Section F of the Fact Sheet for Emission Units F-1 and F-2. "Beginning May 1, 2007, GenOn shall not operate Morgantown Unit 1 unless it has installed and continuously operates, on a year-round basis, Selective Catalytic Reduction technology ("SCR") (or equivalent NO_X control technology approved pursuant to Paragraph 55) so as to achieve a 30-Day Rolling Average Emission Rate from such Unit not greater than 0.100 lb/mmBTU NO_X." **[Reference: Potomac River Consent Decree, Condition 53**] ***SCR was placed into operation on Unit 1 prior to May 2007.*** "Beginning May 1, 2008, GenOn shall not operate Morgantown Unit 2 unless it has installed and continuously operates, on a year-round basis, SCR (or an equivalent NO_X control technology approved pursuant to Paragraph 55) so as to achieve a 30-Day Rolling Average Emission Rate from such Unit not greater than 0.100 lb/mmBTU NO_X." **[Reference: Potomac River Consent Decree, Condition 54**] ***SCR was placed into operation on Unit 2 prior to May 2008.*** (5) 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. (6) 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. Allowance transfer deadline means, for a control period in a given year,

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	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.
1.2	**Testing Requirements:** A. Control of Visible Emissions: For the 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 the Scrubber Stack: The Permittee shall schedule monthly observations of visible emissions from the stack by a person trained to perform Method 9 observations. **[Reference: COMAR 26.11.03.06C]**

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	B. Control of Particulate Matter: For the By-pass Stack: When in operation, the Permittee shall schedule monthly observations from the stack by a person trained to perform Method 9 observations. **[Reference: COMAR 26.11.03.06C]** For the Scrubber Stack: The Permittee shall perform an annual stack test in accordance with EPA Reference Methods. The Permittee shall submit a proposed test protocol to the Department for review and approval at least 30 days in advance of the first scheduled test date. Subsequent protocols shall be provided to the Department if the Permittee intends to make any material revisions to the previously submitted stack test protocols. The Permittee shall provide the Department with two weeks advance written notice of any scheduled stack test and shall submit the results of each stack test to the Department no later than 45 days following the stack test. The Permittee may use the annual relative accuracy testing for the PM CEMS to satisfy the annual testing requirement. **[Reference: 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. 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) Control of NO_X Emissions from Coal-Fired Electric Generating Units See Monitoring Requirements.

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	4) Potomac River Consent Decree See Monitoring Requirements. 5) Acid Rain Permit See Monitoring Requirements. 6) Cross-State Air Pollution Rule See Monitoring Requirements.
1.3	**<u>Monitoring Requirements:</u>** A. <u>Control of Visible Emissions</u> <u>For the By-pass Stack</u>: 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]** In the event an FGD must be bypassed for any reason, the Permittee shall operate the opacity CEMS to record opacity for the duration of the bypass. In such event, compliance with applicable opacity limitations may be determined by opacity CEM data. **[Reference: COMAR 26.11.03.06C]** <u>For the Scrubber Stack</u>: The Permittee shall perform monthly Method 9 observation on the exhaust from the scrubber stack for period of thirty (30) minutes. *Additional opacity monitoring requirements*: To ensure compliance with the 20 percent opacity limit at higher particulate emission rates, the facility shall begin conducting Method 9 opacity observations whenever the 24-hour block particulate emissions equal or exceed 0.03 lbs/MMBtu of heat input. The Method 9 opacity observations shall be conducted for 1-hour each day and continue until the 24-hour particulate block average is less than 0.03 lb/MMBtu heat input for the affected unit. **[Reference: COMAR 26.11.03.06C]** B. <u>Control of Particulate Matter</u>: <u>For By-pass Stack</u>: See the requirements of the CAM Plan (Table IV-1b) <u>For the Scrubber Stack</u>: The Permittee shall operate and maintain a particulate matter continuous emissions monitoring system (PM CEMS). **[Reference: COMAR 26.11.03.06C]**

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C. Control of Sulfur Oxides
For 1) through 3):
The Permittee shall continuously monitor sulfur dioxide emissions using a CEM that meets 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 NAAQS SO_2 standard, the Healthy 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), 2), 4) & 5):
The Permittee shall operate, calibrate, and maintain a certified NO_X CEM or an alternative NO_X monitoring method approved by the Department and the EPA on each installation. [**Reference: COMAR 26.11.09.08C(3)]**
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)]**

3) Control of NO_X Emissions from Coal-Fired Electric Generating Units
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:

Affected Unit	24-Hour Block Average NO_X Emissions in lbs/MMBtu

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Morgantown	
Unit 1	0.07
Unit 2	0.07

(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_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_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_X emission rates of this chapter.

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	(1) Compliance with the NO_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. 6) 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_X Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NO_X 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)]** A. Control of Visible Emissions For the By-pass Stack: The Permittee shall maintain all records necessary to comply with the data reporting requirements of COMAR 26.11.01.11E on file**. [Reference COMAR 26.11.01.11E].** For the Scrubber Stack: The Permittee shall keep records of the results of the any opacity observations from the stack**. [Reference: COMAR 26.11.03.06C**] B. Control of Particulate Matter: For the By-pass Stack: The Permittee shall maintain records as required by CAM Plan. **See Table IV-1b.** For the Scrubber Stack: The Permittee shall maintain records of all particulate matter emissions tests and PM CEMS hourly data. **[Reference: COMAR 26.11.03.06C**] C. Control of Sulfur Oxides 1) The Permittee shall maintain all records necessary to comply with data reporting requirements of COMAR 26.11.01.11E(2). **[Reference COMAR 26.11.01.11E(2)]**.

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	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. D. <u>Control of Nitrogen Oxides</u> 1) NO_X RACT Requirements The Permittee shall maintain records necessary for the quarterly emission reports. **[Reference: COMAR 26.11.03.06C]** 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) Control of NO_X Emissions from Coal-Fired Electric Generating Units The Permittee shall maintain records sufficient to demonstrate compliance with requirements in COMAR 26.11.38. **[Reference: COMAR 26.11.03.06C]** 4) Potomac River Consent Decree 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]** 5) Acid Rain Permit The Acid Rain Permit contains program specific recordkeeping requirements. **[Reference: 40 CFR Part 75, Subpart F].** 6) 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_X Annual Trading Program and

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	§97.506, §97.530, and §97.534 for the NO_X Ozone Season Trading Program.
1.5	**Reporting Requirements:** A. Control of Visible Emissions For the By-pass Stack: 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(2)]** 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 Permittee shall report data from any opacity observation in the next required quarterly report. The Permittee shall also report CEM particulate matter data with the opacity observation data.

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	[Reference: COMAR 26.11.03.06C] B. Control of Particulate Matter: For the By-pass Stack: The Permittee shall submit reports as required by CAM Plan. **See Table IV-1b**. For the Scrubber Stack: 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 a quarterly report of the PM CEMS data. **[Reference: COMAR 26.11.03.06C]** C. Control of Sulfur Oxides 1) 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(2)(c)(i) through (vii). **[Reference: COMAR 26.11.01.11E(2)]**. 2) 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(2)(c)(i) through (vii). **[Reference: COMAR 26.11.01.11E(2)]**. 3) 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 NO_X and SO_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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4) Acid Rain Permit
The Acid Rain Permit contains program specific reporting requirements. **[Reference: 40 CFR Part 75, Subpart G].**

5) 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) NO_X 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(2) [**Reference: COMAR 26.11.09.08K(1) and COMAR 26.11.03.06C]**

2) Emission Limitation for Power Plants Requirements:
COMAR 26.11.27.05 - 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_X and SO_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) Control of NO_X Emissions from Coal-Fired Electric Generating Units
COMAR 26.11.38.06 – 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

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	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_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. 4) 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: Potomac River Consent Decree. **[Reference: COMAR 26.11.03.06C]** 5) Acid Rain Permit The Acid Rain Permit contains program specific reporting requirements. **[Reference: 40 CFR Part 75, Subpart G].** 6) 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 NO_X Annual Trading Program and §97.506, §97.530, §97.533, and §97.534 for the NO_X Ozone Season Trading Program.

"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): F1 and F2: Boilers Cont'd** **Potomac River Consent Decree** **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)
1a.1	**Applicable Standards/Limits**: D. Control of Nitrogen Oxides "Beginning May 1, 2007, the Permittee shall not operate Morgantown Unit

Table IV – 1a – Potomac River Consent Decree

1 unless it has installed and continuously operates, on a year-round basis, Selective Catalytic Reduction technology ("SCR") (or equivalent NO_X control technology approved pursuant to Paragraph 55) so as to achieve a 30-Day Rolling Average Emission Rate from such Unit not greater than 0.100 lb/mmBTU NO_X." **[Reference: Potomac River Consent Decree, Condition 53**]
SCR placed into operation on Unit 1 prior to May 2007

"Beginning May 1, 2008, the Permittee shall not operate Morgantown Unit 2 unless it has installed and continuously operates, on a year-round basis, SCR (or an equivalent NO_X control technology approved pursuant to Paragraph 55) so as to achieve a 30-Day Rolling Average Emission Rate from such Unit not greater than 0.100 lb/mmBTU NO_X." **[Reference: Potomac River Consent Decree, Condition 54**]
SCR placed into operation on Unit 2 prior to May 2008.

System-wide Annual Tonnage Limitations for NO_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_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 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 A

Applicable Year	System-Wide Annual Tonnage Limitations for NO_X
2010 and each year after	16,000 tons

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_X in Table B below:

Table IV – 1a – Potomac River Consent Decree

[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

Applicable Ozone Season	System-Wide Ozone Season Tonnage Limitations for NO_X
2010 and each ozone season thereafter	5,200 tons

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_X.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 59.]

4. If GenOn exceeds the limitations specified in Section IV, Subsection C (System-Wide Annual Tonnage Limitations for NO_X) or D (System-Wide Ozone Season Emissions Limitations), GenOn may not claim compliance with this Decree by using, tendering, or otherwise applying NO_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_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_X trading program set forth in the Maryland State Implementation Plan including the Maryland NO_X Reduction and Trading Program, COMAR

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	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_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 GE GenOn System. Only to the extent that such allowances are insufficient to establish compliance with the requirements of those SIPs, GenOn may use NO_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_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_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_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_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_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_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. **[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 71]**

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	9. In order to sell or transfer NO_X Allowances pursuant to Paragraph 63, GenOn must also timely report the generation of such NO_X Allowances in accordance with Section IX (Periodic Reporting) of this Consent Decree. **[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 64.]** 10. For purpose of this Subsection, the “surrender of allowances” means permanently surrendering NO_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. **[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 65.]** 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_X allowances equal to the amount by which the Ozone Season NO_X allowances allocated to all GenOn System Units for a particular ozone season are greater than the GenOn System-Wide Ozone Season Tonnage Limitations for NO_X established in Paragraph 58 of the Consent Decree for the same year; and (2) the number of “annual” (non-ozone season) NO_X allowances equal to the amount by which the “annual” NO_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_X established in Paragraph 57 and the System Wide Ozone Season Tonnage Limitations for NO_X established in Paragraph 58 for that same year. **[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 66]** 12. If any NO_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_X Allowances and a listing of the serial numbers of the transferred NO_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_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_X Allowances, GenOn shall include a statement that the

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	third-party recipient(s) tendered the NO_X Allowances for permanent surrender to Plaintiffs in accordance with the provisions of Paragraph 68 within one (1) year after GenOn transferred the NO_X Allowances to them. GenOn shall not have complied with the NO_X Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred NO_X Allowances to Plaintiffs. **[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 67]** 13. For all NO_X Allowances surrendered to Plaintiffs, GenOn or the non-profit third-party recipient(s) (as the case may be) shall first submit a NO_X Allowance transfer request form to EPA directing the transfer of such NO_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_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_X Allowances being surrendered. **[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 68]** E. 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_X Emission Limitations, Section XX. Severing the Dickerson Plant: Revised System-wide NO_X Emission Limitations, XXI Severing the Morgantown and Dickerson Plants: Revised System-wide NO_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]** F. Monitoring, and Record Keeping and Reporting Requirements 16. In determining Emission Rates for NO_X, GenOn shall use CEMs in

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	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 NO_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, paragraphs 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,

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	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 [NO_X, SO_2, 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		
Electrostatic Precipitator (ESP) for UNIT 1 (Bypass Stack only)		
Applicable Requirement	**PM:** Emission limit: 0.14 pounds particulate matter per million Btu of heat input **Opacity**: 20 percent maximum	
	Indicator #1	Indicator #2
	Opacity at Stack	ESP Secondary Power
Measurement Approach	The stack continuous opacity monitor (COM) produces 1-minute average readings, which are then used to produce 6-minute averages and block 1-hour averages	The ESP total secondary power is calculated from voltmeters reading secondary voltage and ammeters reading secondary current. Block 1-hour averages are produced from 1-minute averages.
II. Indicator Range	The opacity indicator range is a block hourly average opacity of 17.0%. When the block hourly average opacity is over 19.0%, operators must look at the second CAM indicator, ESP total secondary power.	The total ESP secondary power indicator range is a block hourly average of 417 kW. Excursions below this indicator range trigger corrective actions and reporting requirements.
III. Performance Criteria		
1. Data Representativeness	The COM was installed on the stack per 40 CFR 60, Appendix B.	The voltmeters and ammeters are part of the ESP design and included in their instrumentation.
2. AQ/QC Practices and Criteria	QA/QC per 40 CFR 60, Appendix B	Voltmeters and ammeters and checked per standard PM schedule
3. Monitoring Frequency	Opacity is monitored continuously by the continuous opacity monitoring (COM) system.	Secondary power is monitored continuously by the plant information (Pi) system.
4. Record keeping	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.
5. (i) Reporting	Report the number, duration and cause of any excursion and the corrective action taken.	Report the number, duration and cause of any excursion and the corrective action taken.
(ii) Frequency	Quarterly	Quarterly

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

Table IV-1c		
COMPLIANCE ASSURANCE MONITORING (CAM) PLAN		
Electrostatic Precipitator (ESP) for UNIT 2 (Bypass Stack only)		
Applicable Requirement	**PM:** Emission limit: 0.14 pounds per million Btu of heat input **Opacity**: 20 percent maximum	
I. Indicator	Indicator #1	Indicator #2
	Opacity at Stack	ESP Third Field Secondary Power
Measurement Approach	The stack continuous opacity monitor (COM) produces 1-minute average readings, which are then used to produce 6-minute averages and block 1-hour averages	The ESP third field secondary power is calculated from voltmeters reading secondary voltage and ammeters reading secondary current. Block 1-hour averages are produced from 1-minute averages.
II. Indicator Range	The opacity indicator range is a block hourly average opacity of 18%. When the block hourly average opacity is over 18%, operators must look at the second CAM plan indicator, ESP third field secondary power	The ESP third field secondary power indicator range is a block hourly average of 92 kW. Excursions below this indicator range trigger corrective actions and reporting requirements.
III. Performance Criteria		
1. Data Representativeness	The COM was installed on the stack per 40 CFR 60, Appendix B	The voltmeters and ammeters are part of the ESP design and included in their instrumentation.
2. AQ/QC Practices and Criteria	QA/QC per 40 CFR 60, Appendix B	Voltmeters and ammeters are checked per standard PM schedule.
3. Monitoring Frequency	Opacity is monitored continuously by the continuous opacity monitoring system (COM).	Secondary power is monitored continuously by the plant information (Pi) system.
4. Record keeping	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.
5. (i) Reporting	Report the number, duration and cause of any excursion and the corrective action taken.	Report the number, duration and cause of any excursion and the corrective action taken.
(ii) Frequency	Quarterly	Quarterly

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

Table IV – 1d – CPCN #9085: FGD System	
1d.0	**<u>Emissions Unit Number(s): FGD System for F1 and F2</u>** A wet flue gas desulfurization (FGD) system is installed on both Units 1 and 2. The FGD system controls acid gases (SO_2 & HCl) and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing gypsum 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 three (3) emergency diesel engines (two quench pump and one fire pump). **[CPCN: #9085]**
1d.1	**<u>Applicable Standards/Limits</u>:** **[Reference: CPCN #9085: II. Applicable Air Quality Regulations]** 10. The Morgantown 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_2, NO_X and either O_2 or CO_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 51, Appendix P, §3.3-3.8 or §3.9 as incorporated by reference. b) **COMAR 26.11.03.19**-Requires GenOn to notify MDE and EPA and at renewal to update the existing Morgantown Part 70 Operating Permit (No. 24-017-00014) to include applicable APC Project requirements. ***(Completed)*** c) **COMAR 26.11.06.02C(1)-**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 greater than 20 percent opacity. d) **COMAR 26.11.06.03B(1)-**Prohibits GenOn from discharging into the outdoor atmosphere from any confined source (i.e., the limestone, gypsum and other material storage silos) particulate matter in excess of 0.05 grains per dry standard cubic feet (gr/dscf)(115 mg/dscm). e) **COMAR 26.11.06.03C(1)-**Prohibits GenOn from causing or permitting emissions from an unconfined (fugitive) 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

Table IV – 1d – CPCN #9085: FGD System	
	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 Morgantown APC Project (limestone, gypsum, and sorbent to control sulfuric acid mist emissions), 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 26.11.09.05A(1)-**Prohibits GenOn from discharging emissions from fuel burning equipment, other than water in an uncombined form, which is greater than 20 percent opacity. Exceptions: limitations do not apply during times of load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment which are not greater than 40 percent opacity and do not occur for more than six consecutive minutes in any 60 minute period.

Table IV – 1d – CPCN #9085: FGD System	
	j) **COMAR 26.11.09.05E(2) and E(3)**-Prohibits the discharge of emissions from the quench pump engines, 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 two 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. k) **COMAR 26.11.09.06A(1)**-Prohibits GenOn from causing or permitting particulate matter emissions from Morgantown Units 1 and 2 in excess of 0.14 lb/MMBtu. (Figure 1 of COMAR 26.11.09.06A). [*Compliance with the March 6, 2008 Consent Decree PM Emission limit 0.100 mmBtu/hr (State-only) indicates compliance with COMAR 26.11.09.06A]* l) **COMAR 26.11.09.07A(1)(a)**-Prohibits GenOn from burning coal that would result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu actual heat input. m) **COMAR 26.11.09.07A(1)(c)-**Prohibits GenOn from burning distillate fuel oil in the quench pumps with a sulfur content greater than 0.3 percent. n) **COMAR 26.11.27**-Requires GenOn to comply with the applicable emissions limitations for NO_X, SO_2 and mercury as well as the monitoring and record keeping requirements contained in COMAR 26.11.27. **[Reference: CPCN #9085: III. New Source Performance Standard (NSPS) Requirements]** 12. The equipment at Morgantown identified in [CPCN 9085] Table 1a, Table 1b and Table 1c 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,

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	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 seven percent opacity. 13. Each of the three diesel engine-driven (two quench pumps and one fire pump) 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 #9085: IV. Operational Restrictions and Limitations]** 14. GenOn shall: a) Install, maintain and operate the new limestone, gypsum, sulfuric acid mist (SAM) control sorbent, and hydrated lime unloading, storage, transfer and distribution equipment and systems with associated particulate matter control methods listed in [CPCN 9085] Table 1a-c and Table 2 in accordance with original design criteria, vendor recommendations and best management practices, and in such a manner as to ensure full and continuous compliance with all applicable regulations. b) Update Morgantown's Best Management Practices (BMP) Plan, as required by the facility's Part 70 Operating Permit (Permit No. 24-017-0014), to include the new limestone, gypsum, SAM control sorbent, and hydrated lime transfer storage and distribution equipment. The Plan shall document what reasonable precautions 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 that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and preventative maintenance 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 9085] Table 1a-c and Table 2, GenOn shall submit a request to ARA to amend the facility's BMP Plan. The request shall specify the proposed change(s)

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	in emissions control systems; shall demonstrate that the change(s) will not result in any increases in any pollutants; and update [CPCN 9085] Table 1a-c and Table 2 of these conditions. GenOn shall be authorized to make the changes proposed in the written request unless ARA denies the request within 30 days of the receipt of the request. **[Reference: CPCN #9085: Miscellaneous]** 86. Sulfuric acid mist emissions from Units 1 and 2 combined shall not exceed 1,194 tons per year (tpy) in any rolling 12-month cumulative period. a. Mirant shall maintain records of monthly and 12-month rolling total emissions of SAM from Units 1 and 2 and submit to ARA semi-annually by July 30 for the period January 1 through June 30, and by January 30 for the period July 1 through 31 December; b. At least 30 days prior to the anticipated date of start-up of the APC systems, Mirant shall provide MDE and the PSC with a plan outlining a methodology for determining SAM emissions from Units 1 and 2. Upon approval from ARA, Mirant shall implement the SAM emissions estimating protocol. ***(Completed)***
1d.2	**Testing Requirements**: **[Reference: CPCN #9085: V. Testing]** 17. In accordance with COMAR 26.11.01.04A, GenOn may be required by ARA to conduct additional stack tests to determine compliance with COMAR Title 26, Subtitle 11. This testing will be done at a reasonable time.
1d.3	**Monitoring Requirements:** **[Reference: CPCN #9085: VI. Monitoring]** 18. GenOn shall operate CEM systems for SO_2, NO_X and CO_2 or O_2, under 40 CFR part 75 and COM systems for Morgantown Unit 1 and 2. The Permittee shall calculate the Unit's SAM emissions based on the empirical SAM formation relationship found in Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Revision 3 (Southern Company 2005), the SAM emission stack tests results required by the CPCN 9085 Condition 87 (40 CFR 60, Appendix A, Method 8), the actual unit heat input and the actual fuel sulfur content. The Permittee shall use the following formula using the SAM stack test

Table IV – 1d – CPCN #9085: FGD System	
	results adjusted by the average monthly fuel sulfur content and monthly heat input to calculate the monthly and 12 month rolling SAM emissions: Monthly SAM Emissions (tons/month) = SAM Stack test Rate (lbs/mmBtu) x Coal Sulfur Adjustment Factor (average Monthly Coal Sulfur Content/Stack Test Coal Sulfur Content)/2000 lbs/ton **[Reference: Letter dated Dec 10, 2009 to MDE from Mirant Mid Atlantic LLC: Re: CPCN Case #9085, Condition 86b. – Method to Determine Sulfur Acid Mist Emissions from Morgantown Units 1 and 2]**
1d.4	**Record Keeping Requirements:** **[Reference: CPCN #9085: VII. Recordkeeping and Reporting]** 24. All records and logs required by this CPCN shall be maintained at the facility for at least five years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of ARA.
1d.5	**Reporting Requirements:** **[Reference: CPCN #9085: VII. Recordkeeping and Reporting]** 20. GenOn shall submit to ARA 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. ***(Completed)*** 21. Final results of the performance tests required by this CPCN must be submitted to ARA within 60 days after completion of the test. Analytical data shall be submitted to ARA directly from the emission testing company. ***(Completed)*** 25. All air quality notification and reports required by this CPCN shall be submitted to: Maryland Department of the Environment Administrator, Compliance Program Air and Radiation Administration 1800 Washington Boulevard Baltimore, Maryland 21230

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	26. All notification and reports required by 40 CFR 60 Subpart OOO and Subpart IIII, 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."

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	
1e.0	**Emissions Unit Number(s): F1 and F2 Boilers Cont'd** **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)
1e.1	**Applicable Standards/Limits:** Control of HAPs Emissions **40 CFR Part 63, Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units.** **§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

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	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

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technology installed on the unit consistent with §63.10000(b)."

<u>Table 2</u> to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs
As stated in §63.9991, you must comply with the following applicable emission limits:[1]

If your EGU is in this subcategory...	For the following pollutants ...	You must meet the following emission limits and work practice standards ...	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5...
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (**PM**)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run. **<u>Please Note</u>: PM CEMs will be used.**
	b. Hydrogen chloride (**HCl**)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (**SO_2**)[4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS. **<u>Please Note</u>: SO_2 will be used as a surrogate for HCl pursuant to §63.10000(c1)(v).**
	c. Mercury (**Hg**)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or **Hg CEMS** or sorbent trap monitoring system only..

[1] For 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.
[2] Gross electric output.
[3] Incorporated by reference, see §63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

<u>General Compliance Requirements</u>

§63.10000 - <u>What are my general requirements for complying with this subpart?</u>

"(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

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	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. ***(Completed)*** (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. ***(Completed & On-going)*** (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.** ***(Completed & On-going)*** (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. ***(Completed & On-going)*** (A) *Not Applicable*.

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(B) *Not Applicable*.
(d) *Not Applicable*.
"(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) *Not Applicable*.
(g) *Not Applicable*.
(h) *Not Applicable*.
(i) *Not Applicable*.
"(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." ***(Completed and On-going)***

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:

If your EGU is...	You must meet the following...
1. An **existing** EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48

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			calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
		3. A **coal-fired**, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU **during startup** **Note:** Morgantown selected option 1.	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 in §63.10011(g) and §63.10021(h) and (i).
			(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.
			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).
			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.
			You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case,

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		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.
		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.
	4. A **coal-fired**, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU **during shutdown**	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.
		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	

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	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) *Not Applicable*. (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 **SO_2 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 SO_2 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, CO_2, O_2, 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) *Not Applicable*. (b) *Not Applicable*. (c) *Not Applicable*. (d) *Not Applicable*. (d)(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_2 , HCl, or HF emissions limit in Table 1 or **2** to this subpart through use of an SO_2 , HCl, or HF CEMS installed and operated in accordance with

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	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 SO_2, 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_{hj} 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."***(Completed)*** "(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." (g) *Not Applicable*. (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

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results of your initial compliance demonstration, as provided in §63.10030."

§63.10006 - When must I conduct subsequent performance tests or tune-ups?
(a) *Not Applicable*.
(b) *Not Applicable*.
"(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) *Not Applicable*.
(g) *Not Applicable*.
(h) *Not Applicable*.
"(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to §63.10021(e).
(1) *Not Applicable*..
(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in §63.10021(e) must be no more than **48 calendar months** after the previous performance tune-up."

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]

To conduct a performance test for the following pollutant...	Using...	You must perform the following activities, as applicable to your input- or output-based emission limit...	Using[2]...
1. Filterable Particulate matter (**PM**)	**PM CEMS**	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.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring	Part 75 of this chapter and §§63.10010(a), (b), (c), and (d).

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		systems	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	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)).
3. Hydrogen chloride (**HCl**) and hydrogen fluoride (**HF**)	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		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).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	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)).
	<u>Please Note</u>: SO_2 will be used as a surrogate for HCl pursuant to §63.10000(c1)(v). See #5 SO_2 CEMS		
4. Mercury **(Hg)**	**Hg CEMS**	a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		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).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to this subpart.
5. Sulfur dioxide (**SO_2**)	**SO_2CEMS**	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and §§63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas,	Part 75 of this chapter and §§63.10010(a), (b), (c), and

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		flow rate, and/or moisture monitoring systems	(d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	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)).

[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:

$$Reported\ Result = \frac{(Measured\ Concentration\ in\ Stack)}{\%R} x\, 100$$

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

"(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, **SO_2**, 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) *Not Applicable*.

(3) *Not Applicable*.

(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.

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

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	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 × 10^{-7} lb/scf-ppm for SO_2, 9.43 × 10^{-8}lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18 × 10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24 × 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

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	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 feasible to certify and quality-assure the data from a monitoring system on

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	<u>the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements</u>." "(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_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_2 or CO_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_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_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_2 CEMS has a span value of 30 ppm or less. (3) Calculate and record a 30-boiler operating day rolling average SO_2

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	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 SO_2 emission rates in the preceding 30 boiler operating days. (4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 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 SO_2 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 SO_2 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,

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	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*.

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	§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. (b) *Not Applicable.* (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. ***(Completed)*** (2) For a unit that uses a **CEMS to measure SO_2 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 SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart." ***(Completed)*** "(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to §63.10030(e). ***(Completed)*** (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. ***(Completed & On-going)*** (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,

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	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

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	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

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	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. (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. $\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.\ 8)$ 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

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	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. ***(Completed & On-going)*** (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_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_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_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_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls,

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	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_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_X and O_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_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 in hard copy, as specified in §63.10031(f)(5), through June 30, 2018. On or after July 1, 2018, report the date of all tune-ups electronically, in accordance with §63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed." "(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

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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.

(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) 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.

(i) You must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown."

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:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards...	You demonstrate continuous compliance by...
1. **CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions**, or using a sorbent trap monitoring system to measure Hg	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.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in §63.10021(e).

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6. Work practice standards for **coal-fired**, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for **coal-fired**, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with Table 3.

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

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	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** - <u>In what form and how long must I keep my records?</u> "(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	**<u>Reporting Requirements</u>:** <u>Control of HAPs Emissions</u> **<u>Notification, Reports, and Records</u>** **§63.10030** - <u>What notifications must I submit and when?</u> "(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."

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	“(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 (7), 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

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	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; (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.”

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	§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. ***(Completed and On-going)*** (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

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	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 SO_2 CEMS. Use units of standard cubic meters per hour on a wet basis for flow rates. (iv) *Not Applicable*. (v) *Not Applicable*. (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) *Not Applicable*. (f)(1) On or after **July 1, 2018**, within 60 days after the date of completing each CEMS (**SO_2, PM, HCl, HF, and Hg**) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative

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	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. (f)(2) On or after **July 1, 2018**, 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 the EPA's WebFIRE database by using the CEDRI that is accessed through the 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. (f)(3) Reports for an **SO_2 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). (f)(4) On or after **July 1, 2018**, 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 the EPA's WebFIRE database by using the CEDRI that is accessed through the 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

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	reporting form output format. (f)(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. (f)(6) Prior to **July 1, 2018**, 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;

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(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:

You must submit a...	The report must contain...	You must submit the report...
1. Compliance report	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	Semiannually according to the requirements in §63.10031(b).
	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 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."

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2.0	**<u>Emissions Unit Number(s): F-CT1 thru F-CT6: Combustion Turbines</u>** **F-CT1 and F-CT2** – Two (2) General Electric Frame-5 combustion turbines each rated at 20 MW and used for black start capability and peaking service. These combustion turbines are fired on No. 2 fuel oil. The exhaust gas is vented to single 20 ft high stacks. **[4-0068 & 4-0069]** **F-CT3, F-CT4, F-CT5, F-CT6** – Four (4) General Electric Frame 7 combustion turbine each rated at 65 MW and used for peaking service. These combustion turbines are fired on No. 2 fuel oil. The exhaust gas is vented to single 20 ft high stacks. [**4-0070, 4-0071, 4-0073 & 4-0074]**
2.1	**<u>Applicable Standards/Limits</u>:** A. <u>Control of Visible Emissions</u> **COMAR 26.11.09.05A (1) & (3)** – <u>Fuel Burning Equipment</u> "Areas I, II, V, and VI. In Areas I, II, V, and VI, 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 greater than 20 percent opacity. <u>Exceptions</u>. 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. <u>Control of Sulfur Oxides</u> **COMAR 26.11.09.07A(1)** - <u>Sulfur Content Limitations for Fuel</u>. "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 I, II, V and VI: (a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour; (b) Residual fuel oils, 2.0 percent; **(c) Distillate fuel oils, 0.3 percent;** (d) Process gas used as fuel, 0.3 percent."

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	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." (2) A person who owns or operates a combustion turbine with a capacity factor greater than 15 percent shall meet an hourly average NO_X emission rate of not more than 42 ppm when burning gas or 65 ppm when burning fuel oil (dry volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive." **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. 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

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	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.
2.2	**<u>Testing Requirements</u>:** A. <u>Control of Visible Emissions</u>: See Monitoring Requirements. B. <u>Control of Sulfur Oxides</u>: See Monitoring Requirements. C. <u>Control of Nitrogen Oxides</u>: 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	**<u>Monitoring Requirements:</u>** A. <u>Control of Visible Emissions</u>

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	The Permittee shall verify that visible emissions are less than 20 percent opacity. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period once every 168 hours of operation or at a minimum once per year. The Permittee shall perform the following, if emissions are visible to human observer in excess of 20 percent opacity: (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. The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily when combustion turbine operating for 18 minutes until corrective action have reduce visible emissions to less than 20 percent opacity. **[Reference: COMAR 26.11.03.06C]** B. <u>Control of Sulfur Oxides:</u> 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. <u>Control of Nitrogen Oxides</u>: See Record Keeping Requirements. **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_X Annual Trading Program and §97.506, §97.530, §97.531, §97.532, and §97.533 for the NO_X Ozone Season Trading Program.
2.4	**<u>Record Keeping Requirements</u>:** **<u>Note:</u>** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. <u>Control of Visible Emissions</u> The Permittee shall keep a copy of the visible emissions readings and the certification of the visible emission reader(s) for at least five years on site and make available to the Department upon request. [**Reference: COMAR 26.11.03.06C**]

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	B. Control of Sulfur Oxides: The Permittee shall maintain records of fuel supplier's certification 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. [**Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]** **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_X Annual Trading Program and §97.506, §97.530, and §97.534 for the NO_X Ozone Season Trading Program.
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". 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].** **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 NO_X Annual Trading Program and §97.506, §97.530, §97.533, and §97.534 for the NO_X Ozone Season Trading Program.

"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): F-Aux1, F-Aux 3, and F-Aux4: Auxiliary Boilers** **F-Aux1, F-Aux 3, and F-Aux4** - Three (3) Auxiliary boilers, manufactured by CE-Alstom, used for start-up steam and space heating. Auxiliary boilers are fired with No.2 fuel oil and each have a maximum rating of 164 mmBtu/hr. **[4-0015, 4-0017 & 4-0018]**
3.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A (1) & (3)** – Fuel Burning Equipment "Areas I, II, V and VI. In Areas I, II, V and VI, 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 greater than 20 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(1)** - 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 I, II, V and VI: (a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour; (b) Residual fuel oils, 2.0 percent; **(c) Distillate fuel oils, 0.3 percent;** (d) Process gas used as fuel, 0.3 percent." C. Control of Nitrogen Oxides **COMAR 26.11.09.08G**. - Requirements for Fuel-Burning Equipment with a

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	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) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and (e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request." **Note: COMAR 26.11.09.08B(5)(a)** states that "for the purpose 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".
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 The Permittee shall perform a combustion analysis and optimize combustion at least once annually for any of the auxiliary boiler that operates more than 500 hours during a calendar year. [**Reference: COMAR 26.11.09.08G(1)(b)]**
3.3	**Monitoring Requirements:** A. Control of Visible Emissions

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	The Permittee shall verify that visible emissions are less than 20 percent opacity. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period semiannually. The Permittee shall perform the following, if emissions are visible to human observer in excess of 20 percent opacity: (a) inspect combustion control system and boiler operations, (b) perform all necessary adjustments and/or repairs to the boiler 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 auxiliary boiler. The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily for an 18 minute period until corrective action have reduce visible emissions to less than 20 percent opacity. **[Reference: COMAR 26.11.03.06C]** B. <u>Control of Sulfur Oxides</u> The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil complies with the limitation on sulfur content of the fuel oil. **[Reference: COMAR 26.11.03.06C].** C. <u>Control of Nitrogen Oxides</u> See Record Keeping Requirements.
3.4	**<u>Record Keeping Requirements</u>:** **<u>Note:</u>** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. <u>Control of Visible Emissions</u> The Permittee shall maintain records of all visible emissions observations. **[Reference: COMAR 26.11.03.06C]** B. <u>Control of Sulfur Oxides</u> The Permittee shall retain annual fuel supplier certifications stating that the fuel oil is in compliance with this regulation must be maintained for at least 5 years. **[Reference: COMAR 26.11.09.07C].** C. <u>Control of Nitrogen Oxides</u> The Permittee shall maintain records of the results of the combustion analyses on site for at least five years and make them available to the Department and EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**.

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	The Permittee shall maintain record of training program attendance for each operator on site for at least five years and make the records available to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) & COMAR 26.11.03.06C]**.
3.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall report exceedance of 20 percent opacity in accordance with Permit Condition 4,Section III, Plant Wide Condition, "Report of Excess Emissions and Deviations" **[Reference: COMAR 26.11.03.06C]** B. Control of Sulfur Oxides The Permittee shall report annual fuel supplier certification 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 support documentation in Annual Emissions certification Report. **[Reference: COMAR 26.11.03.06C].** The Permittee shall submit a list of trained operators to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) and COMAR 26.11.03.06C].**

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

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3a.0	**Emissions Unit Number(s): F-Aux2: Auxiliary Boilers Cont'd** **F-Aux2** - Auxiliary boiler No. 2 manufactured by CE-Alstom (Model #30VP21808R/48) is used for start-up steam and space heating. Auxiliary boiler No. 2 is fired with #2 fuel oil and has a maximum rating of 219.3 mmBtu/hr. [**4-0191**] **Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units** **§60.40b** - Applicability (a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity

Table IV – 3a	
	from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).
3a.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A (1) & (3)** – Fuel Burning Equipment "Areas I, II, V and VI. In Areas I, II, V and VI, 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 greater than 20 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 Particulate Matter **§60.43b** – Standard for particulate matter. "(**f**) On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity." "(**g**) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction." **§60.46b** – Compliance and performance test methods and procedures for particulate matter and nitrogen oxides "(a) The particulate matter emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction, and as specified in paragraphs (i) and (j) of this section. The nitrogen oxides emission standards under §60.44b apply at all times." C. Control of Sulfur Oxides **COMAR 26.11.09.07A(1)** - 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 I, II, V and VI:

Table IV – 3a	
	(a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour; (b) Residual fuel oils, 2.0 percent; **(c) Distillate fuel oils, 0.3 percent;** (d) Process gas used as fuel, 0.3 percent." **§60.42b** – Standard for sulfur dioxide. "(**d**) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraph (d)(1), (2), or (3) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under this paragraph. (1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a Federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less; (2) Affected facilities located in a noncontinental area; or (3) Affected facilities combusting coal or oil, alone or in combination with any other fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner." D. 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;

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(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) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request."

Note: COMAR 26.11.09.08B(5)(a) states that "for the purpose 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".

§60.44b – Standard for nitrogen oxides
"(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance test for any affected facilities that: (1) Combust, alone or in combination only natural gas, **distillate oil**, or residual oil with a nitrogen content of 0.30 weight percent or less; (2) Have a combined annual capacity factor of 10 percent or less for natural gas, **distillate oil**, and residual oil with a nitrogen content of 0.30 weight percent or less and (3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to firing of natural gas, **distillate oil**, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, **distillate oil** and residual oil and a nitrogen content of 0.30 weight percent or less."

E. Operational Limit:
[Reference: CPCN Case #8949, Condition III – Operating Requirements]
(1) Operation of the auxiliary boiler shall not exceed 182,458 mmBtu in any consecutive 12-month period.
(2) Emissions from the auxiliary boiler shall not exceed the rates in the following table:

Pollutant	Maximum Short term rates (lb/mmBtu)*	Maximum Emission Rate (tons per year)
NO_X	0.30	27
SO_2	0.50	40

Table IV – 3a	
	PM10 | 0.10 | 15 * Emissions are in pounds per million Btu on a 24-hour average basis.
3a.2	**Testing Requirements:** A. Control of Visible Emissions See Monitoring Requirements. B. Control of Particulate Matter: **§60.46b** – Compliance and performance test methods and procedures for **particulate matter** and nitrogen oxides "(b) Compliance with the particulate matter emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j)." C. Control of Sulfur Oxides: **§60.45b** – Compliance and performance test methods and procedures for sulfur dioxide. "(**a**) The sulfur dioxide emission standards under §60.42b apply at all times." "(**j**) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described §60.49b(r)." D. Control of Nitrogen Oxides The Permittee shall perform a combustion analysis and optimize combustion at least once annually for any of the auxiliary boiler that operates more than 500 hours during a calendar year. [**Reference: COMAR 26.11.09.08G(1)(b)]**. **§60.46b** – Compliance and performance test methods and procedures for particulate matter and **nitrogen oxides** "(b) Compliance with the particulate matter emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j)." E. Operational Limit: Compliance stack testing of the auxiliary boiler shall be conducted within 180 days of initial start-up to quantify pollutant emissions and demonstrate compliance with the emissions limits specified in Condition III.2 for the following air contaminants: nitrogen oxides ("NO_X") and particulate matter

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	less than 10 microns in diameter (“PM_{10}”). [**Reference: CPCN Case #8949, Condition IV (1)]. (*Completed*)** At least 30 days prior to conducting any compliance stack test, the Permittee shall submit a test protocol to ARA for review. Compliance stack testing shall be conducted in accordance with ARA Technical Memorandum ("TM") 91-01, "Test Methods and Equipment Specifications for Stationary Sources" (January, 1991), as amended by Supplement 1 (1 July 1991), 40 CFR 51, 40 CFR 60, or subsequent test protocols approved by ARA. Test ports shall be located in accordance with TM 91-01 (January 1991), or subsequent or alternative measures approved by ARA. ”). [**Reference: CPCN Case #8949, Condition IV (2)].** (***Completed***) Testing shall be performed when operating at a minimum of 90 percent of the design load. If testing cannot be performed at the minimum load, then the actual load during testing shall become the allowable permitted load unless and until testing is performed while operating at a minimum of 90 percent of the design load. ”). [**Reference: CPCN Case #8949, Condition IV (3)]. (*Completed*)** In accordance with COMAR 26.11.01.04A, GenOn may be required to conduct additional stack tests at any time as may be prescribed by ARA. [**Reference: CPCN Case #8949, Condition IV (4)]** Final results of each compliance stack test must be submitted to ARA within 60 days of completion of the test. Analytical data shall be submitted to ARA directly from the emission testing company. . [**Reference: CPCN Case #8949, Condition IV (5)]. (*Completed*)**
3a.3	**<u>Monitoring Requirements:</u>** A. <u>Control of Visible Emissions</u> The Permittee shall verify that visible emissions are less than 20 percent opacity. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period semiannually. The Permittee shall perform the following, if emissions are visible to human observer in excess of 20 percent opacity: (a) inspect combustion control system and boiler operations, (b) perform all necessary adjustments and/or repairs to the boiler 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 auxiliary boiler.

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	The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily for an 18 minute period until corrective action have reduce visible emissions to less than 20 percent opacity. **[Reference: COMAR 26.11.03.06C]** B. Control of Particulate Matter: **§60.48b -** Emission monitoring for **particulate matter** and nitrogen oxides. (j) Units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less **are not required to conduct PM emissions monitoring** if they maintain fuel supplier certifications of the sulfur content of the fuels burned. C. Control of Sulfur Oxides The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil complies with the limitation on sulfur content of the fuel oil. **[Reference: COMAR 26.11.03.06C].** **§60.47b** – Emission monitoring for sulfur dioxide "(**f**) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r)." D. Control of Nitrogen Oxides See Record Keeping Requirements. **§60.48b** – Emission monitoring for particulate matter and **nitrogen oxides**. (i)"The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a continuous monitoring system for measuring nitrogen oxides emissions." §60.13(i) – "After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following: (2) Alternative monitoring requirements when the affected facility is infrequently operated." E. Operational Limit The Permittee shall calculate the monthly mmBtu over the previous 12-

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	month period for the auxiliary boiler to maintain compliance with the 182,458-mmBtu limit. **[Reference: COMAR 26.11.03.06C]**
3a.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 records of all visible emissions observations. **[Reference: COMAR 26.11.03.06C]** B. Control of Particulate Matter See Monitoring Requirements. C. Control of Sulfur Oxides The Permittee shall retain annual fuel supplier certifications stating that the fuel oil is in compliance with this regulation must be maintained for at least 5 years. **[Reference: COMAR 26.11.09.07C].** **§60.49b –** Reporting and recordkeeping requirements "(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period." D. Control of Nitrogen Oxides The Permittee shall maintain records of the results of the combustion analyses and any stack tests on site for at least five years and make them available to the Department and EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**. The Permittee shall maintain record of training program attendance for each operator on site for at least five years and make the records available to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) & COMAR 26.11.03.06C]**. E. Operational Limit The Permittee shall maintain records of the higher heating value of each

Table IV – 3a	
	shipment of fuel. **[Reference: CPCN Case #8949, Condition V (1)]**
3a.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall report exceedance of 20 percent opacity in accordance with Permit Condition 4,Section III, Plant Wide Condition, "Report of Excess Emissions and Deviations" B. Control of Particulate Matter. See Monitoring Requirements C. Control of Sulfur Oxides The Permittee shall report annual fuel supplier certification to the Department upon request. **[Reference: COMAR 26.11.09.07C].** D. 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 26.11.03.06C].** The Permittee shall submit a list of trained operators to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) and COMAR 26.11.03.06C].** **§60.49b -** Reporting and record keeping requirements. (v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format. (w) The reporting period for the reports required under this subpart is each 6-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

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	E. Operational Limit **§60.49b** – Reporting and record keeping requirements. "(**a**) The owner or operator of each affected facility shall submit notification of the date of initial startup as provided by §60.7." *Completed* "(**d**) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month." "(**f**) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity." "(**h**) The owner or operator of any affected facility in any category listed in paragraphs (h) (1) or (2) of this section is required to submit excess emissions reports for any excess emissions which occurred during the reporting period." "(**j**) The owner or operator of any affected facility subject to the sulfur dioxide standards under §60.42b shall submit reports." "(**o**) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record." "(**r**) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period." "(**w**) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period."

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

Table IV – 3b – MACT Subpart DDDDD	
3b.0	**Emissions Unit Number(s): F-Aux1, F-Aux2 F-Aux 3, and F-Aux4: Auxiliary Boilers Cont'd** **F-Aux1, F-Aux 3, and F-Aux4** - Three (3) Auxiliary boilers, manufactured by CE-Alstom, used for start-up steam and space heating. Auxiliary boilers are fired with #2 fuel oil and each have a maximum rating of 164 mmBtu/hr. **[4-0015, 4-0017 & 4-0018]** **F-Aux2** - Auxiliary boiler No. 2 manufactured by CE-Alstom (Model #30VP21808R/48) is used for start-up steam and space heating. Auxiliary boiler No. 2 is fired with #2 fuel oil and has a maximum rating of 219.3 mmBtu/hr. [**4-0191**]
3b.1	**Applicable Standards/Limits:** Control of HAPs Emissions **40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters** **§63.7485 -** Am I subject to this subpart? You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575. **§63.7495 -** When do I have to comply with this subpart? "(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later. (b) If you have an **existing boiler** or process heater, you must comply with this subpart no later than **January 31, 2016**, except as provided in §63.6(i)." "(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 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) These standards apply at all times the affected unit is operating, except

Table IV – 3b – MACT Subpart DDDDD

during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart."

§63.7500 - What emission limitations, work practice standards, and operating limits must I meet?
"(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart."
"(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart."

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards
As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or **a limited use boiler** or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.

Limited-use boiler *or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. [§63.7575]

General Compliance Requirements
§63.7505 - What are my general requirements for complying with this subpart?
"(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f)."

Operational Limits:
[Reference: §63.12]
F-Aux1, F-Aux 3, and F-Aux4: Auxiliary Boilers 1, 3, & 4 operations shall be limited to an annual capacity factor of 10 percent or less or an annual heat input of not greater than 143,664 million Btu each.
F-Aux2: Auxiliary Boiler 2 operation shall be limited to an annual capacity

Table IV – 3b – MACT Subpart DDDDD	
	factor of 10 percent or less or an annual heat input of not greater than 182,458 million Btu. These units shall be defined as limit use boilers as defined in §63.7500(c) & §63.7575.
3b.2	**Testing Requirements:** Control of HAPs Emissions See Monitoring Requirements.
3b.3	**Monitoring Requirements:** Control of HAPs Emissions **Continuous Compliance Requirements** **§63.7540 -** How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards? "(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section." "(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio. (i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment; (ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available; (iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and

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	ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection; (iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject; (v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the 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). Measurements may be taken using a portable CO analyzer; and (vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section, (A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater; (B) A description of any corrective actions taken as a part of the tune-up; and (C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit." "(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or **meets the definition of limited-use boiler or process heater in §63.7575**, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months." "(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup."
3b.4	**<u>Record Keeping Requirements</u>:** **<u>Note</u>:** All records must be maintained for a period of 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]**

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	Control of HAPs Emissions **Notification, Reports, and Records** **§63.7555 -** What records must I keep? "(a) You must keep records according to paragraphs (a)(1) and (2) of this section. (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 tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii)." **§63.7560 -** 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, or they must be accessible from on site (for example, through a computer network), 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."
3b.5	**Reporting Requirements:** Control of HAPs Emissions **Notification, Reports, and Records** **§63.7545 -** What notifications must I submit and when? "(a) You must submit to the Administrator 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 affected source before January 31, 2013, **you must submit an Initial Notification not later than 120 days after January 31, 2013. *Completed*** (c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

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	(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin. “(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8). **§63.7550** - <u>What reports must I submit and when?</u> “(a) You must submit each report in Table 9 to this subpart that applies to you. (b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report. (1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in §63.7495. (2) The first compliance report must be postmarked or submitted 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 each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

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	(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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31. (4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31. (c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule. (1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section. (2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section. (3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section. (4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section. (5)(i) Company and Facility name and address. (ii) Process unit information, emissions limitations, and operating parameter limitations. (iii) Date of report and beginning and ending dates of the reporting period. (iv) The total operating time during the reporting period. (v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit. (vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. (vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since

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	the last performance test that could increase emissions. (viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). (ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel. (x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g). (xi) If there are no deviations from any emission limits or operating limits in

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	this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period. (xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period. (xiii) If a malfunction occurred during the reporting period, the 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. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction. (xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. (xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i). (xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data. (xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. (d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section. (1) A description of the deviation and which emission limit or operating limit from which you deviated. (2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken. (3) If the deviation occurred during an annual performance test, provide

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	the date the annual performance test was completed. (e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d). (1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from). (2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks. (3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8). (4) The date and time that each deviation started and stopped. (5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period. (6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes. (7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period. (8) A brief description of the source for which there was a deviation. (9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation. (f)-(g) [Reserved] (h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section. (1) Within 60 days after the date of completing each performance test (defined in §63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in §63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using 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

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	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 the 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 the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator. (2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator. (3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in §63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.”

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

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4.0	**<u>Emissions Unit Number(s): Coal Barge Unloader</u>** The barge loading facility consists of a dock, barge unloader, a transfer and distribution system and a railcar loading facility. The barge unloader system

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	is sized to unload up to 5.0 million tons of coal per year. The barge unloader's transfer and distribution system is integrated into Morgantown's existing coal handling system. (**6-0138, (CPCN #9031)**)
4.1	**<u>Applicable Standards/Limits</u>:** A. <u>Control of Visible Emissions</u> New Source Performance Standards (NSPS) 40 CFR 60 Subpart Y—Standards of Performance for Coal Preparation Plant (**40 CFR §60.250**) (and the associated notification and testing requirements of 40 CFR §60.7, §60.8 and §60.11) which requirements include: (a) GenOn shall not cause to be discharged into the atmosphere gases from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system being constructed or modified by the Barge Unloading project which exhibit 20 percent opacity or greater (under 40 CFR §60.252(c)). Specifically, equipment that makes up the modified facilities includes: (1) Mechanical barge unloader; (2) Four conveyor transfer points; (3) Transfer point to rail car loading station; (4) Railcar loading station; and (5) Breaker building. (b) The opacity standards shall apply at all times except during periods of startup, shutdown, or malfunction; (c) At all times, including during periods of startup, shutdown and malfunction, GenOn shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. **[Reference: CPCN #9031, condition 10]** B. <u>Control of Particulate Matter</u> **COMAR 26.11.06.03D**. - <u>Particulate Matter from Materials Handling and Construction</u>. 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 coal piles, unloading, transfer, and loading operation at GenOn's Coal Barge Unloading Project, these reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer: (1) Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces, which can create airborne dusts. (2) Installation and use of hoods, fans, and dust collectors to enclose and vent the handling of dusty materials.

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	(3) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution **[Reference: CPCN #9031, condition 9c]**
4.2	**<u>Testing Requirements</u>:** A. <u>Control of Visible Emissions</u> Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the coal barge unloading project, GenOn shall conduct performance tests in accordance with the methods in GenOn's ARA-approved Performance Test Plan and furnished ARA and EPA with a written report of the results of such performance test(s). **[Reference: CPCN #9031, condition 14]. *(Completed)*** B. <u>Control of Particulate Matter</u> See Monitoring Requirements.
4.3	**<u>Monitoring Requirements:</u>** A. <u>Control of Visible Emissions</u> GenOn shall perform a monthly inspection of the coal unloading and handling operations to verify that the reasonable precautions (BMPs) in Condition 12 of the CPCN are being implemented. Visible emission or deviations identified during the inspections shall be promptly corrected. [**Reference: CPCN #9031, condition 15]** B. <u>Control of Particulate Matter</u> GenOn shall maintain and operate the following barge unloading equipment and its associated particulate matter control mechanisms with the potential to cause air pollution in accordance with original design criteria, vendor recommendations, and best management practices and in such a manner as to ensure full and continuous compliance with all applicable regulations:

Equipment	Control Mechanism
Barge Unloader	Telescoping Unloader
Conveyors	Covers or Enclosures
Transfer Towers	Enclosure
Railcar Transfer Point and Load out Station	Partial Enclosure

[**Reference: CPCN #9031, condition 12a]**

GenOn shall develop a coal handling best management practices (BMP)

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	Plan for the coal barge unloader, associated conveyor system and railcar load out station to ensure that reasonable precautions will be used to prevent particulate matter from the coal barge unloading project equipment from becoming airborne. BMP's shall include, but are not limited to minimizing the area of permanent openings, using curtains at permanent openings, where feasible, and keeping doorways or other temporary openings closed when not in use. **[Reference: CPCN #9031, condition 12b]**
4.4	**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 GenOn shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the coal unloading and handling facilities and any malfunction of its associated air pollution control equipment (40CFR 60.7(b). [**Reference: CPCN #9031, condition 18]** B. Control of Particulate Matter GenOn shall maintain the written reasonable precautions (BMPs) at the facility. [**Reference: CPCN #9031, condition 16]** GenOn shall keep written records of monthly inspections and maintenance performed under Condition 12 of the CPCN for the purposes of minimizing particulate matter emissions. Records shall include descriptions of the results of the inspection and maintenance, and any deviations and actions taken to address any noted deviations. [**Reference: CPCN #9031, condition 17]** 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 ARA. [**Reference: CPCN #9031, condition 20]**
4.5	**Reporting Requirements:** A. Control of Visible Emissions Within 60 days of the initial startup date, GenOn shall provide ARA a Performance Test Plan that describes the proposed method for conducting the initial performance test that will demonstrate compliance with 40 CFR 60.252 opacity standard for the affected facilities. The Test Plan shall

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	comply with the requirements of §60.8 and §60.11, as they relate to performing opacity observations. [**Reference: CPCN #9031, condition 13]** ***(Completed)*** All notifications and reports required by 40 CFR 60 and Subpart Y, unless specified otherwise, shall be submitted to: Regional Administrator US Environmental Protection Agency Region III 1650 Arch Street Philadelphia, Pennsylvania 19103-2029 [**Reference: CPCN #9031, condition 22]** GenOn shall furnish written notification to ARA and US EPA of the following events: a) The date constructions is commenced postmarked no later than 30 days after such date; ***(Completed)*** b) The anticipated startup date, not more than 60 or less than 30 days prior to such date; ***(Completed)*** c) The actual date of initial startup postmarked within 15 days after such date; ***(Completed)*** d) Notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applied postmarked 60 days or as soon as practicable before the change has commenced; and e) The anticipated date for conducting the initial opacity observations (performance tests) postmarked not less than 30 days prior to such date. ***(Completed)*** **[Reference: CPCN #9031, condition 19]** B. <u>Control of Particulate Matter</u> Written records of monthly inspections and maintenance performed under Condition 12 of the CPCN for the purposes of minimizing particulate matter emissions shall be made available to the Department upon request. **[Reference: COMAR 26.11.06.06C**] All air quality notifications and reports required by this CPCN shall be submitted to: Maryland Department of the Environment Administrator, Compliance Program Air and Radiation Administration 1800 Washington Boulevard

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	Baltimore, Maryland 21230 **[Reference: CPCN #9031, condition 21]**

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

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5.0	**<u>Emissions Unit Number(s): Coal Blending System & Gypsum Barge Loading System</u>** The coal blending system is designed to blend various coals with different characteristics to match the specification of the Morgantown's boilers and air quality control equipment. The coal blending system consists of the following subsystems: new stack-out facilities in the south coal yard; underground reclaim facilities in existing south and north coal yards; reclaim transfer point to integrate the reclaim from the north and south coal yards; refurbished and upgraded emergency reclaim; and enclosed transfer station with dust suppression system.**[(017-0014-6-0154), (CPCN #9148)]** The Gypsum Barge Loading System is to convey and load gypsum produced by the Chalk Point, Dickerson and Morgantown SO_2 FGD systems. The Gypsum Barge Loading System consists of the following subsystems: 1000-tph conveyor system; five transfer towers, one pier tripper conveyor, one telescoping barge load-out conveyor and rail unloading hopper and conveyor for Chalk Point gypsum transfer**.[(017-0014-6-0153),(CPCN #9148)]**
5.1	**<u>Applicable Standards/Limits</u>:** <u>Control of Particulate Matter</u> **COMAR 26.11.06.03D**. - <u>Particulate Matter from Materials Handling and Construction</u>. 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 activities associated with GenOn's Coal Blending/Gypsum Load out Project, these reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer:

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	(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. (4) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution **[Reference: CPCN #9148, condition 11]**
5.2	**Testing Requirements:** Control of Particulate Matter See Monitoring Requirements.
5.3	**Monitoring Requirements:** Control of Particulate Matter GenOn shall update Morgantown's Best Management Practices (BMP) Plan as required by the facility's Part 70 Operating Permit (Permit No. 24-017-00014), to include the equipment and material handling processes associated with the Project. The Plan shall document what reasonable precautions will be used to prevent particulate matter from project equipment and material handling processes from becoming airborne. The Plan shall include a description of the types and frequency of inspections and/or preventative maintenance that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and preventative maintenance have been conducted as proposed. MDE-ARA shall approve the BMP Plan prior to implementation. **[Reference: CPCN #9148, condition 14].** ***(Completed)***
5.4	**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)]** Control of Particulate Matter GenOn shall maintain the written records of inspections, testing and monitoring results, and maintenance performed on Project emissions sources for the purposes of minimizing particulate matter emissions and demonstrating that coal blending/gypsum load out operations are meeting the approved BMP Plan. Records shall include description of the result of

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	any inspection and maintenance. [**Reference: CPCN #9148, condition 15]** All records and logs required by CPCN 9148 shall be maintained at the facility for at least five years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of MDE-ARA. [**Reference: CPCN #9148, condition 17]**
5.5	**<u>Reporting Requirements</u>:** <u>Control of Particulate Matter</u> Written records of inspections and maintenance performed under Condition 14 of the CPCN for the purposes of minimizing particulate matter emissions shall be made available to the Department upon request. **[Reference: COMAR 26.11.06.06C**] All air quality notifications and reports required by this CPCN shall be submitted to: Administrator, Compliance Program Air and Radiation Administration 1800 Washington Boulevard Baltimore, Maryland 21230 **[Reference: CPCN #9148, condition 18]**

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

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6.0	**<u>Emissions Unit Number(s): STAR</u>** The STAR facility processes fly ash in to a Portland cement substitute. The STAR facility is made up of a 140 mmBtu/hr process reactor equipped with a supplemental 65 mmBtu/hr propane heater and a 20 mmBtu/hr propane duct burner. The unit is equipped with a fabric filter baghouse and wet flue gas desulfurization (FGD) scrubber system. Exhaust gases are directed through a 125 foot stack. The STAR process facility includes a fly ash receiving feed silo and a truck unloading facility, a 30,000 ton product storage dome which includes a product silo with a truck loading facility. The reactor, the storage dome and silos are equipped with pneumatic ash transfer systems. (**6-0150 (CPCN #9229)**)

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6.1	**Applicable Standards/Limits:** **[Reference: CPCN #9229 – Emissions and Operational Requirements]** A. Control of Visible Emissions A-7(c) *Visible Emission from General Sources.* – Prohibits GenOn from causing or permitting the discharge of emissions from any installation or building, other than water in an uncombined form, which is greater than 20 percent opacity [COMAR 26.11.06.02C]. B. Control of Particulate Matter Emissions A-7(d) *Particulate Matter from Confined Sources*. – Prohibits GenOn from causing or permitting the discharge into the outdoor atmosphere from any confined source of particulate matter in excess of 0.05 grains per dry standard cubic feet (gr/dscf) or 114 milligrams per dry standard cubic meter (mg/dscm) [COMAR 26.11.06.03B]. A-7(e) *Particulate Matter from Unconfined Sources*. – Prohibits GenOn from causing or permitting the discharge of emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne [COMAR 26.11.06.03C]. A-7(f) *Particulate Matter from Materials Handling and Construction*. – 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 Morgantown STAR Facility, 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 [COMAR 26.11.06.03D].

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C. Control of Sulfur Oxides Emissions
A-7(g) *Sulfur Dioxide Emissions from General Sources*. – Prohibits GenOn from causing or permitting the discharge of emissions in the atmosphere gases containing more than 500 ppm of SO_2 during any 24-hour block average of hourly arithmetic CEMS concentrations [COMAR 26.11.06.05B(1)]

A-7(h) *Sulfuric Acid Emissions from General Sources*. - Prohibits GenOn from causing or permitting the discharge of emissions in the atmosphere gases containing sulfuric acid, sulfur trioxide, or any combination of them greater than 35 milligrams per cubic meter of emissions of gases reported as sulfuric acid [COMAR 26.11.06.05B(2)]

D. Control of VOC Emissions
A-7(i) *VOC Emissions from General Sources*. – Prohibits GenOn from causing or permitting the discharge of VOC emissions from any installation in excess of 20 lb/day unless the discharge is reduced by 85 percent or more overall [COMAR 26.11.06.06B(2)(c)].

E. Operational Limits
A-8. Annual emissions from the Morgantown STAR Facility shall be less than the following in any consecutive 12-month period, rolling monthly, inclusive of emissions during periods of startup, shutdown and malfunction:

Pollutant	Emissions Limit for Entire Morgantown STAR Facility (Tons per year)
Sulfur Dioxide (SO_2)	40
Nitrogen Oxides (NO_X)	25
Carbon Monoxide (CO)	100
SO_2 or NO_X as a Particulate Matter less than 2.5 microns ($PM_{2.5}$) precursor	40

These federally enforceable limits are necessary for the Morgantown STAR Facility project to avoid triggering major modification requirements under Nonattainment New Source Review (NA-NSR) and Prevention of Significant Deterioration (PSD).

A-9. GenOn shall install, maintain, and operate the Morgantown STAR Facility equipment inclusive of the fabric filter baghouse and wet FGD scrubber system air pollution control technologies, in accordance with the

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	original design criteria, vendor recommendations and best management practices, and in such a manner to ensure full and continuous compliance with all applicable requirements. The baghouse and wet FGD scrubber shall be in place and operational whenever the STAR process reactor is running [COMAR 26.11.02.02H]. A-10. GenOn is only permitted to process fly ash at the STAR Facility obtained from Morgantown, Chalk Point, and Dickerson Generating Stations [COMAR 26.11.02.02H]. A-11. The Morgantown STAR Facility shall not exceed an annual throughput of 360,000 tons of fly ash in any consecutive 12-month period, rolling monthly [COMAR 26.11.02.02H]. A-12. GenOn is only permitted to use propane as an auxiliary fuel [COMAR 26.11.02.02H].
6.2	**<u>Testing Requirements</u>:** A. <u>Control of Visible Emissions</u> The Permittee shall conduct visible emission observations using EPA Method 9 during the annual stack testing of stationary sources**. [Reference: CPCN #9229, condition A-16(c)]** B. <u>Control of Particulate Matter Emissions</u> *From Confined Source*: The Permittee shall perform annual stack testing to demonstrate compliance with PM emission limit in the exhaust gases of the stack of the stationary sources. **[Reference: COMAR 26.11.03.06C]** *From Unconfined Source:* See Monitoring Requirements. C. <u>Control of Sulfur Oxides Emissions</u> See Operational Limits. D. <u>Control of VOC Emissions</u> See Record Keeping Requirements. E. <u>Operational Limits</u> See Monitoring Requirements.
6.3	**<u>Monitoring Requirements:</u>** A. <u>Control of Visible Emissions</u> The Permittee shall visually inspect the exhaust gases from baghouse for

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visible emissions once a month for an 18-minute period and shall record the results of each observation. If visible emissions are observed, the Permittee shall perform the following:
(a) Inspect all process and/or control equipment that may affect visible emissions;
(b) Perform all necessary repairs and/or adjustments to all processes and/or control equipment within 48 hours so that visible emissions in the exhaust gases are eliminated;
(c) Document in writing the results if the inspections and the repairs and/or adjustments made to the processes and/or control equipment; and
(d) If visible emissions have not been eliminated within 48 hours, the Permittee shall perform a Method 9 observation once daily for an 18-minute period until the opacity standard of 20 percent is achieved.
[**Reference: COMAR 26.11.03.06C**].

B. Control of Particulate Matter Emissions
From Confined Source: The Permittee shall develop and implement a preventive maintenance plan for the baghouse that describes the maintenance activity and time schedule for completing each activity. The Permittee shall perform maintenance activities within the timeframes established in the plan and maintain a log with records of the dates that maintenance was performed. [**Reference: COMAR 26.11.03.06C**].
From Unconfined Source: **[Reference: CPCN #9229 – Best Management Practice Requirements]**
A-33. GenOn shall update Morgantown's Best Management Practices (BMP) Plan as required by the facility's Part 70 Operating Permit (Permit No. 24-017-00014), to include the STAR Facility ash beneficiation process and associated control equipment and material handling processes associated with the project. The Plan shall document what reasonable precautions will be used to prevent PM from project equipment and material handling processes from becoming airborne. The Plan shall include a description of the types and frequency of inspections and/or preventative maintenance that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and preventative maintenance have been conducted as proposed. MDE-ARA shall approve the BMP Plan prior to implementation [COMAR 26.11.02.02H]. (***Completed)***

C. Control of Sulfur Oxides Emissions
See Operational Limits.

D. Control of VOC Emissions

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	See Best Management Plan Requirements listed under Control of Particulate Emissions. E. <u>Operational Limits</u> **[Reference: CPCN #9229 – Testing and Monitoring Requirements]** A-13. To demonstrate continuous compliance with the federally enforceable emissions limits set forth in Condition A-8, GenOn shall install, maintain, and operate a continuous emissions monitoring system (CEMS) for SO_2, NO_X, CO and CO_2 or O_2 for emissions from the STAR process reactor through the exhaust stack in accordance with a CEMS Monitoring Plan approved by MDE-ARA [COMAR 26.11.02.02H]. A-14. In accordance with operation of the CEMS, the Morgantown STAR Facility is subject to the following requirements: a) Except as otherwise approved by the MDE-ARA, if GenOn is unable to obtain emissions data from CEMS because of a malfunction of the CEMS for more than 2 hours in duration, GenOn shall use the alternative measurement method approved by MDE-ARA; b) The CEMS shall meet the quality assurance criteria of 40 CFR Part 60, Appendix F, as amended, which is incorporated by reference, or if applicable, the quality assurance criteria of 40 CFR 75, Appendix B, as amended; c) Mass emission rates of NO_X, SO_2 and CO in pounds per hour (lb/hr), and heat input in million Btu per hour (MMBtu/hr) or million Btu per day (MMBtu/day) shall be calculated using the equations and emissions factors presented in 40 CFR Part 75, Appendix F; d) As part of the emission calculation determination using 40 CFR Part 75, Appendix F, GenOn shall obtain a site-specific F-factor (representing a ratio of volume of dry flue gases generated to the calorific value of the fuel combusted or a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted). The site-specific F-factor shall be determined annually in accordance with the methodology on 40 CFR Part 75, Appendix F. e) The CEMS shall record not less than four equally spaced data points per hour and automatically reduce data in terms of averaging times consistent with the applicable emission standard; and f) The use of CEMS for enforcement purposes shall be as specified in MDE-ARA's Technical Memorandum 90-01 "Continuous Emissions Monitoring (CEMS) Policies and Procedures," which is incorporated by reference [COMAR 26.11.02.02H]

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6.4	**Record Keeping Requirements:** A. Control of Visible Emissions The Permittee shall maintain on site for at least five (5) years records of the visible emission observations completed during the annual stack testing of the stationary sources. **[Reference: CPCN #9229 condition A-31]** B. Control of Particulate Matter Emissions *From Confined Source:* The Permittee shall maintain a copy of the preventative maintenance plan and a record of the dates of and description of maintenance activity performed. The Permittee shall keep records of baghouse malfunctions and the corrective actions taken to bring it into proper operation. **[Reference: COMAR 26.11.03.06C]** *From Unconfined Source:* **[Reference: CPCN #9229 – Best Management Practice Requirements]** A-34. GenOn shall keep written records of inspections, testing and monitoring results and maintenance performed on the Morgantown STAR Facility emissions sources for the purpose of minimizing PM emissions and demonstrating that the project operations are meeting the approved BMP Plan. Records shall include descriptions of the result of any inspection and maintenance [COMAR 26.11.02.02H]. C. Control of Sulfur Oxides Emissions See Operational Limits D. Control of VOC Emissions See Best Management Plan Requirements listed under Control of Particulate Emissions. E. Operational Limits **[Reference: CPCN #9229 – Testing and Monitoring Requirements]** A-18. GenOn shall maintain a log of maintenance performed on the STAR process baghouse and wet FGD scrubber. The log of maintenance performed shall include record of dates, a description of the maintenance activity performed, a description of the reason for the maintenance activity (e.g. specific failure, routine) and other corrective actions taken to bring the control equipment into proper operation, if necessary. GenOn shall make maintenance records available to MDE-ARA upon request [COMAR 26.11.02.02H] A-19. GenOn shall maintain a record of the STAR Facility fly ash and propane gas monthly throughput and annual throughput based on

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	consecutive 12-month period, rolling monthly. GenOn shall make such records available to MDE-ARA upon request. Fly ash throughput records shall indicate the original source and date of receipt of the fly ash [COMAR 26.11.02.02H]. A-20. GenOn shall maintain fuel usage, pollutant concentrations, volumetric flow rates, and any other records necessary to determine the STAR Facility SO_2, NO_X, and CO actual emissions. Emission shall be calculated monthly and annually based on a consecutive 12-month period, rolling monthly for comparison with the annual emission limits in Condition A-8 [COMAR 26.11.02.02H]. A-21. GenOn shall maintain on file the following information related to the CEMS and make such records available to MDE-ARA upon request: (a) CEMS or monitoring device performance testing measurements, including but not limited to volumetric flow rates, concentrations, and fuel emissions factors; (b) CEMS performance evaluations and data accuracy audit reports; (c) CEMS calibration checks; (d) Adjustments and maintenance performed on the CEMS; (e) Fuel sampling records required for CEMS calculations; and (f) All other data relevant to maintaining compliance with the emissions limits [COMAR 26.11.02.02H]
6.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall submit to the Department within 60 days after completion of the stack test the results of the visible emission observations taken during the annual stack testing of the stationary sources. **[Reference: CPCN #9229 condition A-26]** B. Control of Particulate Matter Emissions *From Confined Source:* The Permittee shall submit the maintenance plan and record of the maintenance activities to the Department upon request. **[Reference: COMAR 26.11.03.06C]** *From Unconfined Source:* The Permittee shall make available to the Department upon request records of the result of any inspection and maintenance activity performed. **[Reference: COMAR 26.11.03.06C]** C. Control of Sulfur Oxides Emissions See Operational Limits. D. Control of VOC Emissions See Best Management Plan Requirements listed under Control of

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	Particulate Emissions. E. Operational Limits **[Reference: CPCN #9229 – Testing and Monitoring Requirements]** A-27. GenOn shall submit a quarterly monitoring report to MDE-ARA, postmarked by the 30th day following the end of each calendar quarter that includes the following information for the STAR Facility: (a) All instances of deviations from permit requirements; (b) Separately the date, time and duration of each startup, shutdown and malfunction that occurred at the STAR Facility including, but not limited to the ash beneficiation process and associated air pollution control systems. The report shall include total monthly and consecutive 12-month total hours of startup, shutdown and malfunction of the STAR Facility equipment; (c) The downtime or malfunction of the CEMS equipment. The report shall include the date and time of each period during which the CEMS was inoperative and the nature of monitoring system repairs or adjustments completed; (d) The STAR Facility monthly hours of operations and annual hours of operation based on a consecutive 12-month period, rolling monthly; (e) The propane gas monthly usage and annual usage based on a consecutive 12-month period, rolling monthly; and (f) The annual emissions of SO_2, NO_X and CO for the STAR Facility based on a consecutive 12-motnh period, rolling monthly. An algorithm, including example calculations and emission factors, explaining the method used to determine emission rates shall be included in the initial quarterly monitoring report. Subsequent submittals of the algorithm and sample calculations are only required if GenOn changes the method of calculating emissions or changes emissions factors, or if requested by MDE-ARA [COMAR 26.11.02.02H]. A-28. GenOn shall comply with the following conditions for occurrences of excess emission and deviations from the requirements of this permit: (a) Report any deviation from permit requirements that could endanger human health or environment, by orally notifying MDE-ARA immediately upon discovery of deviation [COMAR 26.11.01.07C]. (b) Promptly report occurrences of excess emissions, inclusive of periods of start-up and shutdown, expected to last for one hour or longer by orally notifying MDE-ARA of the onset and termination of the occurrences [COMAR 26.11.01.07C(1)] (c) When requested by MDE-ARA, GenOn shall report all deviations from permit conditions, including those attributable to malfunctions as defined in COMAR 26.11.01.07A, within 5 days of the request by submitting a written

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	description of the deviation to MDE-ARA. The written report must include the cause, dates and times of the onset and termination of the deviation, as well as the action planned or taken to reduce, eliminate and prevent the recurrence of the deviation [COMAR 26.11.02.02H] (d) When requested by MDE-ARA, GenOn shall submit a written report to MDE-ARA within 10 days of receiving the request concerning an occurrence of excess emissions. The report shall contain the information required in COMAR 26.11.01.7C(2) [COMAR 26.11.01.07D(1)]. A-30. GenOn shall monitor and report actual greenhouse gas (GHG) emissions in accordance with 40 CFR Part 98. Reporting is required to begin for actual GHG emissions that are generated in the calendar year in which the facility begins operation, with the report submitted electronically to EPA by 31 March of the following year and annually thereafter [40 CFR Part 98]. A-31. All records and logs required by this CPCN shall be maintained by GenOn at the Morgantown STAR 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 MDE-ARA. A-32. All air quality notifications and reports required by this CPCN shall be submitted to [COMAR 26.11.01.05]: Air Quality Compliance Program Administrator Maryland Department of the Environment 1800 Washington Boulevard, Suite 715 Baltimore, Maryland 21230

"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.

(2) No. 3 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.

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

(4) ✓ 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;

(5) Containers, reservoirs, or tanks used exclusively for:

(a) ✓ Storage of butane, propane, or liquefied petroleum, or natural gas;

(b) No. 15 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;

(6) ✓ 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;

(7) ✓ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

(8) ✓ Potable water treatment equipment, not including air stripping equipment;

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

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

(11) ✓ Laboratory fume hoods and vents;

SECTION VI STATE-ONLY ENFORCEABLE CONDITIONS

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

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."

Emissions Unit Number(s): F1 and F2: Boilers Cont'd **For By-Pass Stack:** **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)
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 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."

March 2008 Opacity Consent Decree

Emissions Unit Number(s): F1 and F2: Boilers Cont'd

March 2008 Opacity Consent Decree
F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**)
F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**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 11, 12, 13, 14, 15, 16, 17, 18.**

PM limit is 0.100 pounds per million Btu of heat input by stack test and 0.100 pounds per million Btu of heat input 24-hour rolling average by PEM. (Condition 32 and 40, March 2008 Consent Decree)

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.***

Completed: **Consent Decree Section X. Installation of Particulate Matter CEMS, paragraph 31.**

Each PM CEMS shall be comprised of a continuous particle mass monitor or equivalent device measuring particulate matter concentration for Morgantown Units 1 and 2 in lbs/mm Btu on a 24-hour rolling average basis. GenOn shall maintain, in an electronic database, the hourly average emission values recorded by all PM CEMS for five (5) years. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 32.]**

March 2008 Opacity Consent Decree
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 VIII. Particulate Matter Stack Testing, paragraph 33.]** *Completed:* **Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 34.** 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 VIII. Particulate Matter Stack Testing, paragraph 35]** GenOn shall submit quarterly PM CEMS reports to the Department that comply with COMAR 26.11.01.11E(2)(c)(i) through (vi). All data shall be reported in 24-hour rolling averages. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 36]** Not Applicable. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 37]** *Completed.* **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 38]** 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

March 2008 Opacity Consent Decree
present in the flue gas stream from such Unit and would impede the accuracy of opacity measurements. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 39]** Morgantown Units 1 and 2 shall be subject to a particulate matter emission limitation of **0.100 lbs/mmBtu heat input**. Compliance with the particulate matter limitation shall be demonstrated by stack test performed in accordance with Paragraphs 26 and 27, and by PM CEMs data in accordance with Section X, except that violations of the particulate matter emission limitation recorded by PM CEMs data shall be subject to §2-611 of the Environmental Article (Plan for Compliance). Violations of the particulate matter standard demonstrated by stack testing are not subject to a Plan for Compliance pursuant to §2-611 of the Environment Article and shall be subject to all sanctions and remedies available to the Department. **[Reference: Consent Decree Section XI. Particulate Matter Limitation Applicable to Morgantown Units 1 and 2, paragraph 40]** Not Applicable. **[Reference: Consent Decree Section XI. Particulate Matter Limitation Applicable to Morgantown Units 1 and 2, paragraph 41 & 42]** <u>Control of Sulfur Emissions</u> GenOn shall ensure that each train of coal scheduled for delivery to the Morgantown Plant for combustion in Units 1 and 2 is sampled for sulfur content prior to delivery. GenOn shall not burn coal that will cause SO_2 emissions in excess of 3.5 lbs/mm Btu heat input. [**Reference: Consent Decree Section III. Coal Sampling, paragraph 5]** <u>Truck Washing Facility</u> GenOn shall commence operation of a Truck Washing Facility designed to reduce fugitive particulate matter emissions at the Morgantown Plant no later than September 30, 2008. Each Truck Washing Facility shall be installed to wash the wheels, undercarriage, and sides of all trucks used to haul fly ash and bottom ash to off-site storage facilities. Each Truck Washing Facility shall consist of a steel basin with ramps on either end, or an array of nozzles that spray high velocity jets of water on the bottom and sides of trucks as they are driven through the device. Water shall be recirculated through a filtration tank. Accumulated ash solids in each filtration tank shall be removed periodically and transported off site to an appropriate ash storage facility in accordance with all applicable local, State and Federal laws and regulations. The truck washing operation may be discontinued when ambient temperatures drop, or are expected to drop, below 36 degrees Fahrenheit, or otherwise when potential freezing would cause or contribute to unsafe conditions. [**Reference: Consent Decree Section XII. Truck Washing Facilities, paragraph 43]**

March 2008 Opacity Consent Decree
<u>Mist Eliminators</u> GenOn shall install and maintain a mist eliminator in each FGD/SO_2 absorber for Morgantown Units 1 and 2, 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] By 12/31/2009.** <u>Reporting Requirements</u> 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]** *Completed*. **[Reference: Consent Decree Section XIV. Reporting, paragraph 46]**

<u>Emissions Unit Number(s): F1 and F2: Boilers [SCR Agreement]</u> **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)
<u>Applicable Standards/Limits</u>: The Permittee shall install and continuously operate two selective reduction (SCR) nitrogen oxide control devices on Units 1 and 2. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]** Subject to Paragraph 3 of this Agreement, GenOn agrees that at all times when either Unit 1 or Unit 2 at the Morgantown Generating Station is operating with an SCR control device, particulate matter emissions from each operating Unit, individually, shall not exceed the emission limitation required by Code of Maryland Regulation (COMAR) 26.11.09.06A, or the Unit's baseline actual particulate matter emissions as determined by 40 CFR 52.21(b)(48), whichever is lower. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the**

MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]

Where baseline actual particulate matter emissions from a Unit subject to this Agreement are lower than the emission limitation required by COMAR 26.11.09.06A, particulate matter emissions from such Unit may exceed the Unit's baseline actual emissions, if and only if, GenOn obtains the Department's approval, by written amendment to this Agreement, to reduce particulate matter emissions from one or more other emission units at the Morgantown Generating Station by an amount equivalent to the increase in actual particulate matter emissions resulting from the installation of the SCR control device. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]**

The ammonia emissions from Unit 1 and Unit 2, individually, shall not exceed 3 parts per million (ppm) determined by a stack test conducted on each Unit in accordance with EPA or Department approved test protocols no later than 180 days following the Unit's initial startup with the SCR control device. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]**

Testing Requirements:
The Permittee shall conduct a stack test for particulate matter emissions on each Unit in accordance with EPA or Department approved test methods no later than 180 days following the Unit's initial startup with the SCR control device.
[Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]

Monitoring Requirements:
COMAR 26.11.01.11 - Continuous Emission Monitoring Requirements.
"A. Applicability and Exemptions.
(1) The provisions of this regulation apply to:
(a) Fuel-burning equipment burning coal that has a rated heat input capacity of 100 million Btu per hour or greater."
"(2) An owner or operator that is required to install a CEM under any federal requirement is also subject to all of the provisions of this regulation."
B. General Requirements for CEMs.
"(1) An owner or operator subject to this regulation shall:
(a) Before installing a CEM, submit to the Department, for approval by the Department and EPA, a plan containing the CEM design specifications, proposed

location, and a description of a proposed alternative measurement method; and
(b) Install and operate a CEM in accordance with the plan approved by the Department and EPA under the provisions of §B(1)(a) of this regulation. "
"(2) The owner or operator of fuel-burning equipment burning coal, with a heat input capacity of 100 million Btu per hour or greater, shall install CEMs to measure and record sulfur dioxide, nitrogen oxide, either oxygen or carbon dioxide, and flow."
"(4) Except as otherwise approved by the Department, if the owner or operator is unable to obtain emissions data from CEMs because of a malfunction of the CEM for more than 2 hours in duration, the owner or operator shall use the alternative measurement method approved by the Department and EPA. "
"C. Quality Assurance for CEMs. A CEM used to monitor a gas concentration shall meet the quality assurance criteria of 40 CFR Part 60, Appendix F, as amended, which is incorporated by reference, or, if applicable, the quality assurance criteria of 40 CFR Part 75, Appendix B, as amended.
D. Monitoring and Determining Compliance.
(1) General. A CEM required by this regulation is the primary method used by the Department to determine compliance or non-compliance with the applicable emission standards established in any permit or approval, administrative or court order, Certificate of Public Convenience and Necessity, or regulation in this subtitle.
(2) Data Reduction. A CEM used to monitor a gas concentration shall record not less than four equally spaced data points per hour and automatically reduce data in terms of averaging times consistent with the applicable emission standard.
E. Record Keeping and Reporting Requirements.
(1) CEM System Downtime Reporting Requirements.
(a) 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.
(b) The system breakdown report required by §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 data that has met performance specifications for accuracy, reliability, and durability of acceptable monitoring systems, as provided in COMAR 26.11.31, and is producing data.
(2) CEM Data Reporting Requirements.
(a) All test results shall be reported in a format approved by the Department.
(b) Certification testing shall be repeated when the Department determines that the CEM data may not meet performance specifications because of component replacement or other conditions that affect the quality of generated data.
(c) A quarterly summary report shall be submitted 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 ability of the CEM to meet performance specifications of emission data;
(iv) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;
(v) Quarterly quality assurance activities;
(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.
(d) All information required by this regulation to be reported to the Department shall be retained and made available for review by the Department for a minimum of 2 years from the time the report is submitted. "

Reporting Requirements:
The Permittee shall submit a stack test protocol to the Department for approval and notify the Department of the scheduled test date at least thirty-(30) days in advance of the test. The Permittee shall submit the stack test results to the Department no later than forty-five (45) days following completion of the test.
[Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]

Emissions Unit Number(s): F1 and F2: Boilers Cont'd

Alternate Operating Scenario for Emission Units F1 & F2

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.

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_X, SO_2 and mercury. Regulations .1-.03, .03E, .05 and .06 related to the reductions of NO_X, and SO_2 emissions were submitted to EPA as a revision to Maryland's State Implementation Plan (SIP) on June 12, 2007. The requirements for NO_X, and SO_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): F1 and F2: Boilers Cont'd

F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**)
F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**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_X, SO_2, and mercury as provided in this regulation.

B. NO_X Emission Limitations.

Healthy Air Act State-Only enforceable NO_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_X allowances equivalent in number to the tons of NO_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 26.11.27.04 - Determining the Mercury Removal Efficiency for Affected Facilities.
A. The procedures of §§B—F of this regulation shall be used to demonstrate compliance with the 12-month rolling average removal efficiency required for mercury by Regulation .03D of this chapter. The owner or operator of an affected facility shall notify the Department of the compliance demonstration method it has elected from §§D—F of this regulation on or before January 1, 2010, for the compliance period that commences on that date and on or before January 1, 2013, for the compliance period that commences on that date. The owner or operator of an electric generating unit that elects to demonstrate compliance with the required mercury removal efficiency by meeting the mass emissions limitation in §F of this regulation shall utilize that same method for all other electric generating units in the system. Once elected for each affected facility or system, as applicable, the option may not be changed during the designated compliance period, but may be changed for the next compliance period.

B. Determining Mercury Content in Coal and Mercury Flue Gas Emission Rates for Each Affected Electric Generating Unit.
(1) The owner or operator of an electric generating unit subject to this regulation shall, at least once each quarter during a consecutive 18-month period beginning not later than July 1, 2007:
(a) Determine the mercury content of the coal utilized by each affected unit using a test method approved by the Department; and
(b) Conduct a combustion gas test to determine the mercury emission rate in the flue gas upstream of any pollution control measure, including fuel mercury beneficiation.
(2) Combustion gas testing and collection of coal samples to determine the mercury content in coal shall be performed on the same day or days.
(3) The mercury emission rate in the flue gas shall be reported as ounces of mercury per trillion Btu heat input.
(4) Combustion gas testing shall be performed using a test protocol approved by

the Department. The test protocol shall be submitted to the Department at least 45 days prior to commencement of testing.
(5) The owner or operator of an affected electric generating unit shall submit to the Department:
(a) The results of tests to determine the mercury content of coal and mercury emission rate in the flue gas upon receipt; and
(b) A demonstration that the combustion gas tests were performed utilizing a coal with a mercury content within the same or lower range as the mercury content of the coal utilized by the electric generating unit during the previous 10 years. *Completed*

C. Determining the Uncontrolled Mercury Flue Gas Baseline for an Affected Facility.
(1) The uncontrolled mercury emission rate in the flue gas of each electric generating unit subject to this chapter shall be determined as the arithmetic average of the quarterly combustion gas tests required by §B of this regulation expressed as ounces per trillion Btu heat input.
(2) The uncontrolled mercury baseline emission rate for an affected facility shall be determined as the heat input weighted average of the emission rates for the coal-fired electric generating units at the affected facility determined in accordance with §C(1) of this regulation.
(3) The uncontrolled mercury baseline emission rate in §C(1) and (2) of this regulation shall be measured upstream of all pollution control measures, including fuel mercury beneficiation. *Completed*

D. Demonstrating Compliance By Measuring Mercury Removal Efficiency.
Compliance with the required mercury removal efficiency is demonstrated at an affected facility when the heat input weighted average of the mercury emission rate of all coal-fired electric generating units at the affected facility, calculated as a 12-month rolling average, is:
(1) For the 12-month period commencing on January 1, 2010, not more than 20 percent of the uncontrolled mercury emission rate established pursuant to §C of this regulation; and
(2) For the 12-month period commencing January 1, 2013 and thereafter, not more than 10 percent of the uncontrolled mercury emission rate established pursuant to §C of this regulation.

E. Demonstrating Compliance by Meeting a Mercury Emission Rate.
(1) Compliance with the required mercury removal efficiency is achieved for an affected facility when the heat input weighted average of the mercury emission rates of all coal-fired electric generating units at the affected facility, measured as a 12-month rolling average, does not exceed the applicable emission rate in §E(2) of this regulation.

(2) Emission Rates.

Affected Facility	Emission Limits Ounces per Trillion Btu Heat Input Beginning	
	January 1, 2010	January 1, 2013
Morgantown	27	14

F. Demonstrating Compliance by Meeting a Mercury Mass Emission Cap.
(1) Compliance with the required mercury removal efficiency is demonstrated at an affected facility when the mass emissions from all affected facilities in a system, measured in pounds as a 12-month rolling average, do not exceed the applicable emission limits in §F(2) of this regulation.

(2) Mercury Emission Limits.

Affected Facility	Emission Limits Pounds per Year Beginning	
	January 1, 2010	January 1, 2013
Morgantown	127	66

(3) In the event that an electric generating unit at an affected facility subject to this chapter permanently ceases operation, the mass emission limitation in §F(2) of this regulation which is applicable to that affected facility shall be reduced proportionally based on the relative capacity, in megawatts, of all the electric generating units at the affected facility which are subject to this regulation.
(4) In the event that an entire affected facility within a system permanently ceases operation, the total mass emission limitation in §F(2) which is applicable to the system shall be reduced by the mass emission limitation applicable to the affected facility.
(5) Except during periods of startup, shutdown, malfunction or maintenance, the owner or operator of an electric generating unit shall ensure that mercury control measures are continuously employed on each unit and properly adjusted for optimal control taking into consideration the operating conditions.

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_X and SO_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): F1 and F2: Boilers Cont'd

F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**)
F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**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): STAR

The STAR facility processes fly ash in to a Portland cement substitute. The STAR facility is made up of a 140 mmBtu/hr process reactor equipped with a supplemental 65 mmBtu/hr propane heater and a 20 mmBtu/hr propane duct burner. The unit is equipped with a fabric filter baghouse and wet flue gas desulfurization scrubber system. Exhaust gases are directed through a 125 foot stack. The STAR process facility includes a fly ash receiving feed silo and a truck unloading facility, a 30,000 ton product storage dome which includes a product silo with a truck loading facility. The reactor, the storage dome and silos are equipped with pneumatic ash transfer systems. (**6-0150 (CPCN 9229)**)

[Reference: CPCN 9229]
A-36. Annual emissions from the Morgan STAR Facility shall be less than the following in consecutive 12-month period, rolling monthly, inclusive of emissions during periods of startup, shutdown and malfunction:

Pollutant	Emission Limit for Entire Morgantown STAR Facility (pounds per year)
Mercury (Hg)	5

A-37. GenOn shall conduct annual performance stack tests of the STAR process reactor to determine compliance with COMAR Title 26, Subtitle 11 for mercury [COMAR 26.11.01.04A. The performance stack tests shall be conducted with a representative composite of fly ash typically combusted in the STAR process reactor at that time. GenOn shall submit a stack test protocol to MDE-ARA for approval, in accordance with Condition A-25.

A-38. GenOn shall analyze samples of the unprocessed fly ash entering the STAR process reactor and the processed fly ash exiting the STAR process reactor or mercury concentration on a monthly basis.

A-39. GenOn shall submit a quarterly monitoring report to MDE-ARA, postmarked by the 30th day following the end of each calendar quarter that includes the following information for the STAR Facility:
(a) The actual emissions of mercury for the STAR Facility based on a consecutive 12-month period, rolling monthly. An algorithm, including example calculations, emissions factors, and monthly throughput, explaining the method used to determine emission rates shall be submitted to MDE-ARA for review and approval at least 60 days prior to the initial quarterly monitoring report. Subsequent submittals of the algorithm and sample calculations are only required if GenOn changes the method of calculating emissions, changes emissions factors, or if requested by MDE-ARA; and
(b) The analysis results for the monthly samples of the unprocessed fly ash and processed fly ash required under Condition A-38.

A-40. GenOn shall maintain any records necessary to determine the STAR Facility mercury actual emissions. Emissions shall be calculated monthly and annually based on a consecutive 12-month period, rolling monthly for comparison with the annual emission limit in Condition A-36.

Maryland Department of the Environment
Air and Radiation Administration

PHASE II ACID RAIN PERMIT

Plant Name: GenOn Mid-Atlantic LLC. – Morgantown Generating Station	
Affected Units: 1 and 2	
Owner: GenOn Mid-Atlantic, LLC	ORIS Code 1573
Effective Date From: December 1, 2017 To: September 30, 2022	

Contents:

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 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 Administration

NOV 27 2017
Date of Issue

Plant Name: GenOn Mid-Atlantic LLC. – Morgantown Generating Station

2. SO_2 and NO_x Requirements for each affected unit

Units No. 1 and 2

SO_2 Requirements	
SO_2 Allowances	GenOn Mid-Atlantic, LLC. – Morgantown Generating Station will hold allowances for each unit in accordance with 40 CFR 72.9(c)(1)

NO_x Requirements					
NO_x Limit	YEAR				
	2014	2015	2016	2017	2018
Unit No. 1	0.45 lb/mmBtu	0.45 lb/mmBtu	0.45 lb/mmBtu	0.45 lb/mmBtu	0.45 lb/mmBtu
Unit No. 2	0.45 lb/mmBtu	0.45 lb/mmBtu	0.45 lb/mmBtu	0.45 lb/mmBtu	0.45 lb/mmBtu

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.

Unit No. 1 and Unit No. 2 are subject to the standard NO_x emission rate for tangentially fired coal fired boilers.

In addition, Units 1 and 2 shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

Renewal Permit Approval

Angel Bianco

George S. Aburn, Jr., Director
Air and Radiation Administration

NOV 27 2017

Date of Issue

Maryland Department of the Environment
Air and Radiation Administration

CO_2 BUDGET TRADING PROGRAM PERMIT

Plant Name: GenOn Mid-Atlantic LLC. - Morgantown Generating Station	
Affected Trading Units: Unit 1, Unit 2, CT-3, CT-4, CT-5, and CT-6	
Owner: GenOn Mid Atlantic LLC	**ORIS Code** 1573
Effective Date From: December 1, 2017 To: September 30, 2022	

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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 Administration issues this permit pursuant to COMAR 26.09.01 thru COMAR 26.09.04.

Initial Permit Approval

George S. Aburn, Jr., Director
Air and Radiation Administration

NOV 27 2017
Date of Issue

2. Affected Units

Unit ID #	ARA ID #	Unit Description
Unit 1	4-0013	640 MWe (approx.) coal fired boiler
Unit 2	4-0014	640 MWe (approx.) coal fired boiler
CT-3	4-0070	65 MWe (approx) No. 2 fuel oil fired combustion turbine
CT-4	4-0071	65 MWe (approx) No. 2 fuel oil fired combustion turbine
CT-5	4-0073	65 MWe (approx) No. 2 fuel oil fired combustion turbine
CT-6	4-0074	65 MWe (approx) No. 2 fuel oil fired combustion turbine

3. Standard Requirements:

(A) Selection and Responsibilities of CO_2 Budget Source Compliance Account Authorized Account Representatives.

(1) Each CO_2 budget source shall have a CO_2 authorized account representative and an alternate CO_2 authorized account representative.
(COMAR 26.09.01.04B)

(2) Upon receipt of a complete account certificate of representation:

(a) The CO_2 authorized account representative and alternate CO_2 authorized account representative shall represent and, by representations, actions, inactions, or submissions, legally bind each owner or operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to this subtitle, notwithstanding any agreement between the CO_2 authorized account representative, alternate CO_2 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 CO_2 authorized account representative or alternate CO_2 authorized account representative by the Department or a court regarding the CO_2 budget source or unit.
(COMAR 26.09.01.04E (2))

(3) A CO_2 budget permit may not be issued or a compliance account established for a CO_2 budget source until the Department has received a complete account certificate of representation for a CO_2 authorized account representative and alternate CO_2 authorized account representative of the source and the CO_2 budget units at the source.
(COMAR 26.09.01.04F)

(4) Each submission shall be signed and certified by the CO_2 authorized account representative or alternate CO_2 authorized account representative on behalf of each CO_2 budget source and shall

include the following statement by the CO_2 authorized account representative or alternate CO_2 authorized account representative: "I am authorized to make the submission on behalf of the owners or operators of the CO_2 budget sources or CO_2 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 CO_2 Allowances And Compliance

(1) Unless otherwise specified in this chapter, a CO_2 budget source shall demonstrate compliance with its CO_2 budget emissions limitation by having one CO_2 allowance in its compliance account for every ton of CO_2 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 CO_2 allowances may be deducted from a compliance account for purposes of complying with a budget source's CO_2 budget emissions limitation for a certain control period

(a) CO_2 allowances that are not CO_2 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) CO_2 allowances that are held or transferred into the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period;

(c) CO_2 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 CO_2 allowances from the CO_2 budget source's compliance account until the number of CO_2 allowances deducted equals the number of tons of total CO_2 emissions, less any CO_2 emissions attributable to the burning of eligible biomass.
(COMAR 26.09.02.03E (3))

(4) The identification of available CO_2 allowances for compliance deduction by serial number or by default is as follows:

(a) The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 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 CO_2 allowances by serial number, the Department shall deduct CO_2 allowances for a control period in the following descending order:

(i) For the first control period, all CO_2 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 CO_2 allowances for a control period allocated to a CO_2 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 CO_2 offset allowances transferred and recorded in the compliance account, in chronological order; and

(iv) Any CO_2 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 CO_2 budget source has excess emissions, the Department shall deduct, from the CO_2 budget source's compliance account, CO_2 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 CO_2 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) CO_2 offset allowances may not be deducted to account for the source's excess emissions.

(d) Any CO_2 allowance deduction does not affect the liability of the owners or operators of the CO_2 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 CO_2 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 CO_2 budget source's compliance account no longer exists, the CO_2 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 CO_2 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 CO_2 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 CO_2 budget source or unit.
(COMAR 26.09.02.02A)

(2) The requirements of this subtitle are effective on January 1, 2009 or, for new CO_2 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 CO_2 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 CO_2 authorized account representative for the source shall submit an initial CO_2 budget permit application by October 1, 2008, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.
(COMAR 26.09.02.04A (2));

(b) The CO_2 budget permit application shall include the following in a format prescribed by the Department: 1) the identification of the CO_2 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 CO_2 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 CO_2 emissions from the unit;

(c) Whether all CO_2 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 CO_2 allowances from, or transfer CO_2 allowances to, a compliance account to correct errors in the account or to accurately reflect CO_2 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 CO_2 budget unit shall:

(a) Install monitoring systems to monitor CO_2 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

$$W_{CO_2} = \frac{\left(MW_C + MW_{O_2}\right) \times W_C}{2{,}000\, MW_C} \quad (Eq.\ G\text{-}1)$$

Where:

W_{CO_2}=CO_2 emitted from combustion, tons/day.

MW_c=Molecular weight of carbon (12.0).

MW_{o2}=Molecular weight of oxygen (32.0)

W_c= 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 CO_2 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 CO_2 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 CO_2 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) CO_2 concentration;

(b) CO_2 emissions rate;

(c) Stack gas moisture content;

(d) Fuel flow rate; and

(e) Any other parameter required to determine CO_2 mass emissions.
(COMAR 26.09.02.10 A (2) (a)-(e))

(9) The owner or operator of a CO_2 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 CO_2 budget unit or a non-CO_2 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_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_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_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_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_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_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_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 mass emissions data for the CO_2 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 CO_2 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, NO_x and SO_2 provisions.
(COMAR 26.09.02.11 B (4))

(5) The CO_2 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 CO_2 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 CO_2 emissions; and

(c) The CO_2 concentration values substituted for missing data under 40 CFR Part 75, Subpart D, do not systematically underestimate CO_2 emissions.
(COMAR 26.09.02.11 B (5) (a)-(c))

(6) The CO_2 authorized account representative of a CO_2 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 CO_2 authorized account representative or alternate CO_2 authorized account representative of a CO_2 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 CO_2 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 CO_2 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 CO_2 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;

(iv) The total eligible biomass fuel heat input; and

(v) Chemical analysis, including heat value and carbon content;

(d) The total amount of CO_2 emitted from the CO_2 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 CO_2 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 CO_2 budget unit shall calculate and submit on a quarterly basis the total dry weight for each distinct type of eligible biomass fired by the CO_2 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) Vj = Total volume (scf) for fuel type j;
(iv) Mj = 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 CO_2 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:

$$CO_2tons = \sum_{j=1}^{n} F_j x C_j x O_j \left(\frac{44\left(\frac{g}{molCO_2}\right)}{12\left(\frac{g}{molC}\right)} \right)(0.0005)$$

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) Oj = 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) $$\frac{44\left(\frac{g}{molCO_2}\right)}{12\left(\frac{g}{molC}\right)}$$

= 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.

(COMAR 26.09.02.11 D (3))

(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))

(14) Report of net Steam Output.

(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 CO_2 budget units;

(e) If the CO_2 budget unit monitors net thermal output, the diagram shall indicate all steam or hot water coming into the net steam system, including steam from CO_2 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 CO_2 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 CO_2 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 CO_2 authorized account representative stating the following, "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 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) CO_2 Emission Offset Projects

(1) In order to qualify for the award of CO_2 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 (SF_6);

(c) Sequestration of carbon due to afforestation;

(d) Reduction or avoidance of CO_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)

KGY April 20, 1979

Title 10
Department of Health and Mental Hygiene
Environmental Health Administration

The Department of Health and Mental Hygiene is proposing adoption of amendments to Regulation .03 Air Pollution Episode System and Regulation .04 Ambient Air Quality Standards under COMAR 10.18.01 Control of Air Pollution in the State; Regulations .02 Control and Prohibition of Visible Emissions, .03 Control and Prohibition of Particulate Matter Emissions, .04 Control and Prohibition of Gas and Vapor Emissions, .06 Control and Prohibition of Certain New Fuel Burning Equipment under COMAR 10.18.02 Air Pollution in Area I, COMAR 10.18.03 Air Pollution in Area II, COMAR 10.18.06 Air Pollution in Area V and COMAR 10.18.07 Air Pollution in Area VI; and Regulation .04 Control and Prohibition of Gas and Vapor Emissions under COMAR 10.18.04 Air Pollution in Area III and COMAR 10.18.05 Air Pollution in Area IV.

The purpose of these amendments is to comply with the legislative mandate now codified at §693(b)(3) to (8), Article 43, Annotated Code of Maryland which, in general, requires the DHMH to establish air quality standards identical to the national ambient air quality standards and emission standards no more restrictive than necessary to attain and maintain the ambient air quality standards. To this end, the proposed amendments will change the State's air quality standards, for the pollutants for which there are federal standards, to be consistent with those standards. They also add a new ambient air quality standard for lead and change the air quality standard and episode criteria to be consistent with the new federal ozone standard. In addition, the proposed amendments also contain substantial change to the State's emission standards.

On a statewide basis, the proposed amendments will relax the emission limitation for nitrogen oxides from solid fuel-fired new fuel burning equipment. In the urban areas, the 0.5 percent sulfur limitation on residual fuel oil, which was to be imposed after July 1, 1980, has been raised to the current 1% limit. The remaining changes are restricted to the rural areas of the State. The major revisions to the rural area regulations are as follows: a relaxation from the existing no visible emission limitation from facilities constructed after January 17, 1972 to 20 percent opacity; removal of the requirement for dust collection devices on residual oil-fired equipment constructed after January 17, 1972; relaxation of the emission limitations for particulate matter from installations constructed after January 17, 1972, including fuel burning equipment, incinerators and asphalt concrete plants, and lowering of the prohibition on construction of new solid fuel burning equipment from 50 to 13 million Btu per hour rated capacity.

There is an additional provision which is being proposed which would require certain sources in Area I to meet a different emission standard for sulfur content of fuels than is required for other sources in the same area. This particular provision must be read in the context of applicable federal regulations in order to be understood. While the existing Maryland regulation imposes a 2 percent sulfur content limitation on residual fuel oil and a 3.5 pound per million BTU limit on sulfur oxides from the combustion of solid fuel, there is a federally enforceable requirement in effect which limits sulfur content of fuel to 1 percent in Area I. This more restrictive federal requirement will remain until the EPA approves this revision to its air quality implementation plan. To date, the EPA has refused to approve the State's relaxation to a 2 percent sulfur emission standard in Area I because of the potential impact on the attainment and maintenance of national ambient air quality standards. The provision in question has been proposed as a means of removing the impediment to federal approval of the State's relaxed standard. The accompanying screening demonstration will identify those sources which would case or exacerbate a violation of federal ambient air quality standards or PSD increments if they were allowed to burn the higher sulfur fuel. Those sources will be required to continue to burn the low sulfur fuels, while all other sources could take advantage of the relaxed sulfur content standard. Use of the Department's screening demonstration techniques indicate that the following fuel burning sources will be restricted to one percent sulfur fuels:

Celanese
Kelly-Springfield Tire
PPG Industries
Potomac Edison
W. D. Byron and Son
Maryland Correctional Institute
Fairchild Republic
Mack Trucks

A similar provision has been included in the proposed regulation controlling particulate matter emissions from other installations (COMAR 10.18.02.03F(3), 10.18.03.03F(3), 10.18.06.03F(3) and 10.18.07.03F(3)). The Department's screening demonstration indicated that an overall relaxation of particulate matter control requirements would in general not exceed National Ambient Air Quality Standards. However, the demonstration revealed that localized problems could be expected in the vicinity of the following sources:

Westvaco (smelt dissolving tanks)
Kelly-Springfield (buffers, tire tread grinders)
Eastalco Aluminum (potline electro-cells, carbon anode furnace)
Stoltzfus and Sons (stone crushing)

Therefore, these sources will be restricted to the existing emission standard of 0.03 gr/SCFD.

The Department anticipates that some changes in style or format, particularly for the sulfur content of fuel regulation and the particulate matter regulation, may be necessary in order to insure enforceability and eventual federal approval of these amendments.

Screening Demonstration Description

To evaluate the impact of the proposed amendments on the Prevention of Significant Deterioration (PSD) increments and the National Ambient Air Quality Standards (NAAQS) for Total Suspended Particulate (TSP) and Sulfur Dioxide (SO_2),[1] concentration estimates were calculated for the amendment-affected sources[2] using emission rates based on the proposed emissions limitations. Annual average emission rates reported in the Maryland registration files were used to predict annual concentrations. For predicting short-term concentrations, hourly emission rates were calculated from annual emissions by dividing annual rates by the sources annual operating hours. Because some sources operated less than 24-hours/day, their hourly emission rates had to be adjusted before 24 hour predictions were made. The adjustment was made, for sources operating less than one shift per day, by dividing the sources' operating hours by 9, where a 9 hour wind persistence is the standard figure used by U.S. EPA. No such adjustment was necessary for the 3 hour averaging time. For predicting PSD increment concentrations, an additional factor was applied to emission rates to represent the emission increases allowed by the proposed amendments. This factor was one for SO_2 sources, since the only other residual oil available in amendment-affected areas contains 100% more sulfur than the currently used oil, and the proposed coal sulfur limit is double the current content. TSP emission rate increases due to the TSP emission standard relaxation are given in the following table.

Type Process	Current Limit (gr/SCFD)	Proposed Limit (gr/SCFD)	Increased Emission Factor
Process with control equipment (built since 1/17/72)	.03	.05	.667
Asphalt Plant (built before 1974)	.03	.05	.667
Asphalt Plant (built since 1974)	.03	.04	.333
Non-pathological incinerator (built since 1/17/72)	.03	.1	2.33

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[1] See Appendix Table I for applicable PSD increments and ambient air quality standards.

[2] For a list of all amendment-affected sources, see Appendix Table II.

Isolated and Major Source Calculations

Because of the different modeling requirements, the affected sources were separated into three categories: major sources, those sources close enough to interact, and those which could be considered isolated. An impact analysis of the isolated sources affect on the short-term PSD increments and NAAQS was performed according to the Guidelines for Air Quality Maintenance and Planning, Vol. 10, Sec. 4.3, 1977. Because a complete set of stack parameters was not available for each source, the following effective stack height assumptions were made when necessary in accordance with the above guidelines:

Plume Condition	Effective Stack Height
Looping	Twice the physical height
Coning	Twice the physical height
Limited Mixing	Physical Height
Fanning	Physical Height

The effective stack height for horizontal stacks was taken to be the physical stack height for all stability classes. For most sources, registration information reported ranges of stack heights (e.g. 31-50'). In those cases, the lowest height was used, and for the 0-30' range, a 15' stack height was assumed. Because of the probable proximity of higher buildings, downwash was assumed to occur at all stacks shorter than 20'. Field observations were made by Air Quality Programs personnel to determine the downwash potential of the following major sources: R. P. Smith (Potomac Edison), Celanese, Kelly-Springfield, PPG Industries, Maryland Correctional Institute, Mack Truck, Fairchild Industries, W. D. Byron, Roper Eastern, and Gilbert Industries. Briggs' Diffusion Estimation for Small Emissions, 1973, Sec. 2.1-3.4 was used to predict ground level concentrations for sources with downwash potential.

School [illegible]

taken & Snyder

To evaluate the impact of premises having more than one source, the guidelines' suggestion for merging stack parameters was utilized when possible. Since merging was usually not possible, ~~a modified CRSTER model~~ Turner's WADE with limited mixing was used to evaluate most of these premises. Since previous Valley model results were available for Westvaco[1], Kelly-Springfield, Celanese and PPG Industries,[2] these results were adopted and modified for

[1] SO_2 results for Westvaco were obtained from a 1976 ERT model run.

[2] Results of previous modeling for Cumberland were given in the Maryland Air Quality Technical Memorandum 77-03, 1977.

use in this analysis.

One hour concentrations predicted by the Guidelines and the Turner's WADE ~~modified CRSTER model~~ were converted to 3-hour and 24-hour concentrations by using the factors suggested in the Guidelines Section 4.2 -- .9 for 3-hour, .4 for 24-hour. Normally, the largest of the max concentrations for each stability class was chosen for comparison to PSD increments and NAAQS. However, max concentrations occurring during E and F stabilities were ignored for sources operated only during the day. Since premise property boundaries were not readily available, concentration estimates occurring 400 meters downwind from a source were chosen for comparison to standards for sources with downwash potential. Table III shows the incremental increases which would result if the relaxations were allowed at those premises. Tables IV and V of the Appendix show those major sources and isolated sources which exceeded Federal standards or PSD increments.

Interacting Sources

Because of the density of proposed amendment-affected sources in Cumberland, Frederick and Hagerstown, models capable of evaluating multi-source interaction in urban areas were employed to predict impact on both annual and short-term PSD increments and NAAQS's. Major sources located nearby these urban areas were also made part of the analysis. Those sources that exceeded standards or increments by previous demonstrations were held to emissions that reflected existing limitations (Table III sources).

The State's Multiple Source Dispersion Model[1] was used to predict concentrations in Frederick and Hagerstown. Meteorological data for these cities were taken from Martinsburg, West Virginia airport. The State's version of EPA's model, C9M3D, was used for the Cumberland analysis. Meteorological data for Cumberland was a combination of wind data from Cumberland City Hall and ceiling height and cloud cover from Pittsburgh.

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1 See description in the 1979 State Implementation Plan Amendments for the Baltimore Intrastate Air Quality Control Region, January, 1979.

Max Predicted in Cumberland 24-hr 2.3, ann 0.3

explanation →

Prediction of the impact on the NAAQS in Cumberland is given in the following table:

where

TSP

City Hall Average Time	Observed Concentrations 1978 (ug/m^3)	Predicted Max. Concentrations (ug/m^3)	Sum (ug/m^3)
24-hour 2nd highest	144	2.3	146.3
Annual	68	0.3	68.3
Workshop for Blind			
24-hour 2nd highest.	127	2.3	129.3
Annual	64	0.3	64.3

Examination of the tables shows no violation of standards or increments. The sources involved are Celanese, Cumberland Contracting and Liller Brothers Asphalt, those for particulate relaxations. There were no SO_2 sources affected.

The following Frederick TSP sources will be relaxed by the proposed amendment: Campbell-Grove, Etzler Co., R. F. Kline, C. J. Miller, North Frederick Elementary School, Fort Detrick, and Walkersville High School. No SO_2 sources were assumed to be close enough to interact. Model results predict a max TSP concentration increase of 1 ug/m^3 for the annual average and 4 ug/m^3 for the 24-hour average. These values are considered insignificant with respect to PSD as indicated in Federal Register, Vol. 43, No. 118.

The following Hagerstown SO_2 and TSP sources will be relaxed by the proposed amendments:

TSP	SO_2
Marquette Cement	Hagerstown Municipal Light Plant
H. B. Mellott	Columbo, Inc.
Blaine Window Hardware	Roper Eastern
Conservit, Inc.	Victor Hosery Corp.
Bester-Long, Inc.	Supreme Concrete Block
O. O. Craig	Jamison Door
	Hagerstown P. O.
	Beachley Furniture
	Manbeck Bread
	Gray Concrete
	Gilbert Industries
	Maryland Machine and Foundry

Predicted maximum concentration increases for Hagerstown are:

Average Time	TSP Concentrations (ug/m^3)	SO_2 Concentrations (ug/m^3)
3-hour	--	28
24-hour	3	17
Annual	1	4

TSP concentrations are insignificant as described above. SO_2 concentrations are significant but below allowed PSD increments.

Impact on the NAAQS's in Hagerstown was evaluated by adding the short term and annual predictions nearest the monitoring sites to the observed highest short term concentration and the observed annual concentration, respectively.

In summary, the smaller interacting sources not screened out by the major and isolated source modeling exercises did not show any interference with PSD increments or National Ambient Air Quality Standards. These sources, therefore, could take full advantage of the relaxation if approved by EPA.

Further Refinements

As proposed at this time, the regulation amendments are based on a conservative analysis of the impacts on ambient air. In many cases several of the input parameters to the screening model may have been overly conservative. Such assumptions were necessary due to the large number of sources affected by the amendment and the limited resources available for the analysis.

It is intended that more refined analysis be undertaken in order that more sources can be benefitted by these amendments. Such refined demonstrations, however, will be carried out by the affected source. In the case of Westvaco, for example, a more refined analysis has been completed by consultants for the company and has demonstrated compliance with air quality standards at the higher emission rates allowed by the amendments. Such higher emissfon rates have been allowed by the Department and, therefore, supercede the effect of this screening demonstration. Pending approval by the EPA, the higher emission rate will be the applicable rate under Federal law as well as State law.

For more information on the more refined level of analysis, contact Mr. Bonta at 383-3245.

APPENDIX

TABLE I

PSD Increments
and
National Air Quality Standards

	Average Time	PSD Increment (ug/m^3)	NAAQS (ug/m^3)	Level of Significance (ug/m^3)
SO_2	3-hour	512	1300*	25
	24-hour	91	365	5
	Annual	20	80	1
TSP	24-hour	37	150*	5
	Annual	19	60#	1

* Secondary standard, all others are primary standards

\# Geometric mean, guideline

Increments are for Class II areas

Annual limits are not to be exceeded. Other standards and increments may be exceeded once annually.

Subtitle 18 AIR QUALITY PROGRAMS

Authority: Article 43, §697,
Annotated Code of Maryland

Notice of Proposed Action

The Department of Health and Mental Hygiene is proposing adoption of amendments to Regulation .03 **Air Pollution Episode System** and Regulation .04 **Ambient Air Quality Standards, under COMAR 10.18.01 Control of Air Pollution in the State; Regulations .02 Control and Prohibition of Visible Emissions, .03 Control and Prohibition of Particulate Matter Emissions, .04 Control and Prohibition of Gas and Vapor Emissions, .06 Control and Prohibition of Certain New Fuel Burning Equipment,** under **COMAR 10.18.02 Air Pollution in Area I, COMAR 10.18.03 Air Pollution in Area II, COMAR 10.18.06 Air Pollution in Area V,** and **COMAR 10.18.07 Air Pollution in Area VI;** and Regulation **.04 Control and Prohibition of Gas and Vapor Emissions,** under **COMAR 10.18.04 Air Pollution in Area III,** and **COMAR 10.18.05 Air Pollution in Area IV.**

The purpose of these amendments is to comply with the legislative mandate now codified at §693(b)(3) to (8), Article 43, Annotated Code of Maryland, which, in general, requires the DHMH to establish air quality standards identical to the national ambient air quality standards and emission standards no more restrictive than necessary to attain and maintain the ambient air quality standards.

The amendments will constitute a revision to the State's Air Quality Implementation Plan and must be submitted to the Environmental Protection Agency for approval pursuant to 40 CFR §51.6. The proposed amendments will change the State's air quality standards, for the pollutants for which there are federal standards, to be consistent with those standards. They also add a new ambient air quality standard for lead and change the air quality episode criteria to be consistent with the new federal ozone standard.

The proposed amendments also contain substantial changes to the State's emission standards. On a statewide basis, the proposed amendments will relax the emission limitation for nitrogen oxides from solid fuel-fired new fuel burning equipment. In the urban areas, the .5 percent sulfur limitation on residual fuel oil, which was to be imposed after July 1, 1980, has been removed. The remaining changes are restricted to the rural areas of the State and represent a relaxation from the existing emission standards. The major revisions to the rural area regulations are as follows: a 20-percent opacity limitation for visible emissions from facilities constructed after January 17, 1972; removal of the requirement for dust collection devices on residual oil-fired equipment constructed after January 17, 1972; relaxation of the emission limitations for particulate matter from installations constructed after January 17, 1972, including fuel burning equipment, incinerators and asphalt concrete plants; and lowering of the prohibition on construction of new solid fuel burning equipment from 50 to 13 million Btu per hour.

There is an additional provision which has been proposed which would require certain sources in Area I to meet a different emission standard for sulfur content of fuels than is required for other sources in the same area. This particular provision must be read in the context of applicable federal regulations in order to be understood. While the existing Maryland regulation imposes a 2 percent sulfur content limitation on residual fuel oil and a 3.5 pound per million Btu limit on sulfur oxides from the combustion of solid fuel, there is a federally enforceable requirement in effect which limits sulfur content of fuel to 1 percent in Area I. This more restrictive federal requirement will remain until the EPA approves the State's regulation as a revision to its air quality implementation plan. To date, the EPA has refused to approve the State's relaxation to a 2 percent sulfur emission standard in Area I because of the potential impact on the attainment and maintenance of national ambient air quality standards. The provision in question has been proposed as a means of removing the impediment to federal approval of the State's relaxed standard. The accompanying demonstration will identify those sources which would cause or exacerbate a violation of federal ambient air quality standards or PSD increments if they were allowed to burn the higher sulfur fuel. Those sources will be required to continue to burn the low sulfur fuels, while all other sources could take advantage of the higher sulfur content standard. Use of the Department's screening techniques indicate that the following fuel burning sources will be restricted to one percent sulfur fuels:

Celanese Corporation
Kelly-Springfield Tire
PPG Industries
Westvaco
Potomac Edison
W. D. Byron and Son
Maryland Correctional Institute
Fairchild Republic
Mack Trucks

A similar provision has been included in the regulation controlling particulate matter emissions from other installations **(COMAR 10.18.02.03F**(3), **10.18.03.03F**(3), **10.18.06.03F**(3), and **10.18.07.03F**(3)). The Department's screening procedure indicated that an overall relaxation of particulate matter control requirements would not adversely affect air quality in general. However, the procedure revealed that localized problems could be expected in the vicinity of the following sources:

Westvaco (smelt dissolving tanks)
Kelly-Springfield (buffers, tire tread grinders)
Eastalco Aluminum (potline electro-cells, carbon anode furnace)
Stoltzfus and Sons (stone crushing)

Therefore, these sources will be restricted to the existing emission standard of .03 gr/SCFD.

The Department anticipates that some changes in style or format, particularly for the sulfur content of fuel regulation and the particulate matter regulation, may be necessary in order to insure enforceability and eventual federal approval of these amendments.

Estimate of Economic Impact

I. **Summary.** These proposed amendments will relax certain emission limitations on facilities located in certain parts of the State and will revise the State's ambient air quality standards to be consistent with the federal standards.

II. Types of Economic Impacts.	Revenue (+) Expense (−)	Magnitude
A. On issuing agency:	None	
B. On other State or local agencies affected:	None	
	Benefit (+) Cost (−)	**Magnitude**
C. On regulated industries or trade groups:		
1. Ability to use higher sulfur fuels.	(+)	Cannot be determined
2. Ability to decrease power usage.	(+)	Cannot be determined
3. No need for dust collector devices on residual oil fired burners.	(+)	Cannot be determined
4. Ability to construct solid fuel burning equipment between 13 & 50 MM Btu.	(+)	Cannot be determined
5. Possible inducement to expansion.	(+)	Cannot be determined
D. On other industries or trade groups affected:		
1. Vendors selling solid fuel burning units less than 50 MM Btu heat input.	(+)	Cannot be determined
2. Vendors of dust collection equipment.	(−)	Cannot be determined
3. Maryland coal producers.	(+)	Cannot be determined
E. Direct and indirect effects on public:		
1. Increase in ambient levels of suspended particulate and sulfur dioxide.	(−)	Cannot be determined
2. Lower costs to the consumer for certain products and services.	(+)	Cannot be determined

III. Assumptions. (Identified by Impact Letter and Number from Section II):

C.1. Assumes fuels with higher sulfur contents cost less than low sulfur fuels. Impossible to assess magnitude because of uncertainty as to which facilities will change fuels, what the sulfur content will be, and what the price differential would be.

2. Assumes that power usage by certain types of control equipment can be reduced.

3. Assumes that facilities can comply with proposed requirements without dust collectors.

4. Assumes that construction of small solid fuel fired fuel burning equipment will be cheaper to construct and/or operate than comparable oil fired units.

D.1. Assumes that vendors of solid fuel burning units less than 50 MM Btu heat input (but greater than 13 MM Btu) will now sell their units in Maryland.

2. Assumes that vendors of dust collection equipment will have a reduced market in Maryland.

3. Assumes that coal use will increase because of increase in the number of small units and ability to use higher sulfur fuel.

E.1. Assumes that any increase in ambient levels of air pollution is associated with increased costs. However, the expected levels will not exceed the Federal health and welfare standards and the increments established to prevent significant deterioration of air quality.

2. Assumes that those facilities which take advantage of relaxed emission limitations will pass on any savings which are realized to the consumer.

Opportunity for Public Comment

The Environmental Health Administration will hold hearings concerning adoption of these amendments June 4, 1979, at 10:30 a.m. in the 2nd Floor Auditorium of the Washington County Health Department, 1302 Pennsylvania Avenue, Hagerstown, Maryland 21740; on June 5, 1979, at 10 a.m. in the Laboratory Auditorium of the Herbert R. O'Conor State Office Building, 201 West Preston Street, Baltimore, Maryland 21201; and on June 8, 1979, at 1 p.m. in Room 106 of the Government Office Building, Route 5 and North Division Street, Salisbury, Maryland 21801.

Written comments may be sent to Raymond A. Huber, Regulations Coordinator, O'Conor Building, Room 314-A, 201 West Preston Street, Baltimore, Maryland 21201. These comments must be received no later than June 8, 1979.

10.18.01 Control of Air Pollution in the State of Maryland

.03 Air Pollution Episode System.

A. (text unchanged)

B. Air Pollution Episode Criteria.

(1) (text unchanged)

(2) Episode Criteria.

(a) (text unchanged)

(b) Alert Stage. An alert shall be declared by the Secretary or his designee when any one or more of the following pollutant levels is attained concurrent with:

(i) A judgment by the Department that the pollutant level is representative of air quality in a significant portion of the region. The Department shall consult the air pollution control agencies of the affected jurisdictions to help evaluate local situations.

(ii) Meteorological conditions are such that pollutant dispersion is expected to be inhibited for 12 or more hours.

(iii) Pollutant levels.

POLLUTANT	LEVEL
(aa) Sulfur dioxide	.3 ppm 24 hour average
(bb) Particulate matter	3.0 COH's 24 hour average
(cc) Sulfur dioxide and particulate matter	Combined product of 24 hour SO_2 and COH's equal to .2
(dd) Carbon monoxide	15 ppm 8 hour average
(ee) **[**Photochemical Oxidant**]** *Ozone*	**[**0.1**]** *.2* ppm 1 hour average
(ff) Nitrogen dioxide	.6 ppm 1 hour average or .15 ppm 24 hour average

(c) Warning Stage. A warning shall be declared by the Secretary or his designee when any one or more of the following pollutant levels is attained concurrent with:

(i)—(ii) (text unchanged)

(iii) Pollutant levels.

POLLUTANT	LEVEL
(aa) Sulfur dioxide	.6 ppm 24 hour average
(bb) Particulate matter	5.0 CHO's 24 hour average
(cc) Sulfur dioxide and particulate matter	Combined product of 24 hour SO_2 and COH's equal to .8
(dd) Carbon monoxide	30 ppm 8 hour average
(ee) [Photochemical Oxidant] *Ozone*	.4 ppm 1 hour average
(ff) Nitrogen dioxide	1.2 ppm 1 hour average or .3 24 hour average

(d) Emergency Stage. An emergency shall be declared by the Governor when any one or more of the following pollutant levels is attained concurrent with:

(i)—(ii) (text unchanged)

(iii) Pollutant levels.

POLLUTANT	LEVEL
(aa) Sulfur dioxide	.8 ppm 24 hour average
(bb) Particulate matter	7.0 COH's 24 hour average
(cc) Sulfur dioxide and particulate matter	Combined product of 24 hour SO_2 and COH's equal to 1.2
(dd) Carbon monoxide	40 ppm 8 hour average
(ee) [Photochemical oxidant] *Ozone*	.5 ppm 1 hour average
(ff) Nitrogen dioxide	1.6 ppm 1 hour average or .4 ppm 24 hour average

(e) (text unchanged)

(3)—(4) (text unchanged)

C.—D. (text unchanged)

.04 Ambient Air Quality Standards.

[A. Definitions. For purposes of the ambient air quality standards in this section only, the following definitions shall apply.

(1) Sulfur oxides means sulfur dioxide, sulfur trioxide, their acids, and the salts of their acids. For purposes of these ambient air quality standards, measurements of sulfur dioxide shall be taken by the methods specified herein to indicate the concentration of sulfur oxides.

(2) "Particulate Matter" means the substances collected from or settling out of, the atmosphere by use of the measurement procedures prescribed in these regulations for suspended particulate matter and dustfall, respectively.

(3) "Non-Methane Hydrocarbons" means a class of organic compounds, excluding methane, whose molecules consist primarily of atoms of hydrogen and carbon and which exist in the ambient air in the gaseous state. Specifically excluded are hydrocarbons and other organic compounds associated only with suspended particles in the atmosphere. For purposes of these air quality standards, non-methane hydrocarbons means the difference between the reported total hydrocarbons and methane values measured by the methods specified herein.

(4) "Photochemical Oxidants" means complex photochemical reactions involving non-methane hydrocarbons, oxides of nitrogen and sunlight that when they occur in the ambient air, result in the formation of photochemical oxidants. For purposes of these ambient air quality standards, the measurement of ozone, the predominant constituent of these oxidants, shall be taken by the method specified in these regulations to indicate the concentration of photochemical oxidants.]

[B. Precepts.

(1) It is known that concentrations of air pollutants above certain levels are harmful to the health of man. However, the threshold levels at which adverse effects of man's health begin are not known with precision. It must be presumed that adverse effects over a long time period take place at concentrations lower than those now known to produce adverse effects over short time periods. Therefore, in establishing air quality standards, it is prudent to provide for margins of safety in reaching conclusions based on available data that relate health effects to pollutant levels.

(2) An ambient air quality standard which would result in avoidable degradation of air quality is in conflict with applicable state law.

(3) The ambient air quality standards set forth in these regulations represent goals expressed in terms of limits on the duration and concentration of pollutants in the atmosphere which are not to be contravened. The ambient air quality standards shall be achieved through application, under provisions of laws or regulations or otherwise, of means for reducing pollutant concentrations including removal of air pollutants from exhaust gas streams, fuel and process and material changes, equipment changes, and land use management.]

[C. Primary Ambient Air Quality Standards for All Substances Which May Cause Air Pollution and Control Measures to be Returned.

(1) The primary ambient air quality standards for all substances which may cause air pollution shall be those lowest concentrations attainable by application of all reasonably available means for reducing pollutant concentrations in the ambient air. In situations where the lower concentrations of any substance in the "more adverse range" as set forth in these regulations are not exceeded, or—when there is no standard at the "more adverse range"—where the "serious level" is not exceeded, all necessary means shall be required for minimizing increases in concentrations of those substances in the ambient air, so that those concentrations shall not be exceeded in the future.

(2) No statement, numerical standards, or time limit, contained elsewhere in ambient air quality standards shall be interpreted as mitigating the necessity for the application of all reasonable means for reducing pollutant concentrations in the ambient air.]

[D. Secondary Ambient Air Quality Standards - More Adverse Range. When ambient air concentrations of any pollutant listed in Table 1, are in the more adverse range, as set forth in Table 1 the application of all necessary means for reducing those concentrations shall be required and the time schedule for their implementation shall be based on the premise that the pollutant concentrations are progressively to be reduced to the lower level or less as set forth in Table 1, within the shortest reasonable time. Such reasonable time should not exceed 7 years, shorter time may be specified under provisions of the Federal Clean Air Act.]

[E. Secondary Ambient Air Quality Standards—Serious Level. When ambient air concentrations of any pollutant listed in Table 1 exceed the serious level, as set forth in Table 1, all necessary means shall be applied to reduce those concentrations. The means required and the time schedule for their implementation shall be based on the premise that the pollutant concentrations are progressively to be reduced to levels lower than the serious levels concentrations set forth in Table 1 in the shortest possible time. If ambient air concentrations exceed the serious levels specified in Table 1 as of the year 1971, such concentrations should be reduced to less than the serious levels by not later than the end of calendar year 1974. If, in the future, ambient air concentrations first exceed the serious level, reduction below the serious level shall occur within 3 years from the year in which the serious level is first exceeded, or in a shorter time, if required under provisions of Federal law or regulations. In determining the means for reducing pollutant concentrations, matters of economics and private interests and other factors shall be subordinate considerations to the necessity of achieving the standards for protection of the public health. Additionally, if standards have been adopted for the more adverse range, measures for reducing concentrations of the pollutant further below the serious level shall be instituted in accordance with the provisions of subsection D, above.]

[F. Method of Measurement. Measurement of ambient air quality to compare to the standards including reporting of measurements for each pollutant listed in Table 1 shall be by the method specified in 40 CFR, 50; 36 FR 22384, Nov. 25, 1971, and the methods manual entitled "Standard Methods for the Determination of Air Pollution Measurements made at Ambient Air Sampling Stations in the State of Marylend", as developed by the Bureau of Air Quality Control of the Department. Other methods may be used if they have been demonstrated to be equally or more specific, accurate, sensitive and reproducible and if first approved by the Department. Other less specific methods of measurement may be used provided a relationship is developed between results obtained by this method and the method specified; provided this relationship is approved by the Department. Results shall be expressed as micrograms or milligrams of the pollutant per cubic meter of air, at 25 degrees Celsius and 760 millimeters of mercury pressure except as specifically noted in Table 1. Such values may be converted to parts per million by volume (ppm) by utilizing the appropriate conversion factor listed in Table 1.]

[G. Number and Duration of Measurement. Pollutant measurements determined by the methods specified may be determined either by operation of cumulative type samplers or by continuous monitoring instruments. Specific definitions of measurement period values and statistical methods to be used to obtain levels for comparison to the standards are as indicated in the following appropriate subsection.

(1) Dustfall. The annual arithmetic average shall be based on at least nine of 12 possible monthly levels that can be determined during a year; there shall be at least two valid monthly levels reported in each calendar quarter.

(2) All Other Cumulative Type Pollutant Measurement.

(a) Daily average levels shall be on a midnight to midnight E.S.T. period with a minimum sampling frequency of every sixth day for each specific date starting January 4, 1972. Samples may be taken on a more frequent schedule provided that samples are also taken on the specified dates.

(b) The annual arithmetic mean shall be based on at least 75 percent of the possible valid daily (24-hour) values obtainable at a location under previously specified sampling schedule, distributed through the year to reflect adequately the mean of 365 possible observations. Other statistical procedures may be used to evaluate the data to determine probable values of missing data, if the methods have been approved previously by the Department.

(3) Continuous Monitoring Instruments. The primary reportable pollutant value for all measurements determined by a continuous monitoring instrument shall be the hourly value; other statistical averages for the averaging times specified in the following subparts may be obtained by appropriately processing the hourly value.

(a) A valid hourly average level shall be based upon at least 58 percent of the possible data obtainable from the system during the hour.

(b) A valid 3-hour value shall be the arithmetic average of at least two of the possible three hourly values during a 3-hour period.

(c) A valid 8-hour value shall be the arithmetic average of at least six of the possible eight hourly values during a day (12 midnight to 12 midnight E.S.T.).

(d) A valid daily (24-hour) value shall be the arithmetic average of at least 18 of the possible 24 hourly values during a day (12 midnight to 12 midnight E.S.T.).

(e) A valid annual average shall be the arithmetic average of at least 65 percent of the possible hourly values, uniformly distributed throughout the calendar year. Less values could be used to compute means, provided it can be shown by acceptable statistical analysis that these means are valid estimates.]

[H. Location of Measurements. Measurements of air pollutants may be made at any place where air pollution could exist.]

A. Definitions and Reference Conditions. For the purposes of §§B—G, below, the definitions, reference conditions, and methods of measurement are specified in 40 CFR Parts 50 and 53, 1977 Edition, 43 FR 46258-46261 (October, 1978) and 44 FR 8202 (February 8, 1979).

B. Sulfur Oxides.

(1) The primary ambient air quality standards for sulfur oxides, measured as sulfur dioxide are:

(a) 80 micrograms per cubic meter (.03 ppm)—annual arithmetic mean;

(b) 365 micrograms per cubic meter (.140 ppm)—maximum 24-hour concentration not to be exceeded more than once per year.

(2) The secondary ambient air quality standard for sulfur oxides, measured as sulfur dioxide, is 1300 micrograms per cubic meter (.50 ppm)—maximum 3 hour concentration not to be exceeded more than once per year.

C. Particulate Matter.

(1) The primary ambient air quality standards for particulate matter are:

(a) 75 micrograms per cubic meter—annual geometric mean;

(b) 260 micrograms per cubic meter—maximum 24-hour concentration not to be exceeded more than once per year.

(2) The secondary ambient air quality standard for particulate matter is 150 micrograms per cubic meter—maximum 24-hour concentration not to be exceeded more than once per year.

D. Carbon Monoxide.

The primary and secondary ambient air quality standards for carbon monoxide are:

(1) 10 milligrams per cubic meter (8 ppm)—maximum 8-hour concentration not to be exceeded more than once per year;

(2) 40 milligrams per cubic meter (35 ppm)—maximum 1-hour concentration not to be exceeded more than once per year.

E. Ozone. The primary and secondary ambient air quality standards for ozone is 235 micrograms per cubic meter (.12 ppm)—the standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above .12 ppm is equal to or less than one.

F. Hydrocarbons. The primary and secondary ambient air quality standard guideline for hydrocarbons is 160 micrograms per cubic meter (.24 ppm)—maximum 3-hour concentration (6 to 9 a.m.) not to be exceeded more than once per year.

G. Nitrogen Dioxide. The primary ambient air quality standard for nitrogen dioxide is 100 micrograms per cubic meter (.05 ppm)—annual arithmetic mean.

H. Lead. The primary and secondary ambient air quality standards for lead are 1.5 micrograms per cubic meter—maximum arithmetic mean averaged over a calendar quarter.

I. [Secondary] Ambient Air Quality Standards for Fluorides.

(1) Ambient air quality standards for fluorides [at the more adverse level shall be] *are* those concentrations in the ambient air *or in other substances* which result in the following values being exceeded:

(a)—(i) (text unchanged)

[(2) Air Pollution Control Measures to be Required. When concentrations of fluoride cause any of the values set forth in (1), above, to be exceeded, the application of all necessary means shall be required for reducing the concentrations. The means to be required and the time schedule for their implementation shall be based on the premise that fluoride concentrations are to be reduced progressively in the shortest possible time to levels that will not cause the values in (1), above, to be exceeded.]

[(3)] *(2)* (text unchanged)

TABLES 1—3 (text unchanged)

[TABLE 4

AMBIENT AIR QUALITY STANDARDS

Pollutant	Frequency	More Adverse Range				Serious Level		Conversion Factor
	Times Values May Be Exceeded per Unit Time	UG/M³ Lower Limit	UG/M³ Upper Limit	PPM Lower Limit	PPM Upper Limit	UG/M³	PPM	
(1) Sulfur oxides (expressed as sulfur dioxide concentrations) Annual arithmetic average[1]	Values not to be exceeded	60	79	0.023	0.03	79	0.03	$\frac{UG/M^3}{2620}$ = PPM
Daily average	Once per year					262	0.10	
One hour average	Once per month					920	0.35	
(2) Particulate matter (a) Suspended particulate Annual arithmetic average		65	75	—	—	75	—	
Daily average	Once per year	140	160	—	—	160	—	
(b) Dustfall Annual arithmetic average	Values not to be exceeded	MG/CM²/Month 0.35	0.50			MG/CM²/month 0.50		$\frac{MG/CM^2}{035}$ = TON/MI²
Monthly average		Lower limit 0.70	Upper limit 1.00			1.0		
(3) Carbon monoxide 8-hr arithmetic average[2]	Once per year	No standard				$\frac{MG/M^3}{10}$	$\frac{PPM}{9}$	MG/M³ × 0.873 = PPM
Hourly average	Once per year	No standard				40	35	
(4) Non-methane hydrocarbons[3] three-hour average[4]	Once per year	No standard				$\frac{UG/M^3}{160}$	$\frac{PPM\ carbon}{0.24}$	$\frac{UG/M^3}{655}$ = PPM
(5) Photochemical oxidants hourly average	Once per year	No standard				$\frac{UG/M^3}{160}$	$\frac{PPM\ ozone}{0.08}$	$\frac{UG/M^3}{1960}$ = PPM
(6) Nitrogen dioxide annual arithmetic average	Values not to be exceeded	No standard				$\frac{UG/M^3}{100}$	$\frac{PPM}{0.05}$	$\frac{UG/M^3}{1882}$ = PPM

References

(1) Annual averages shall be for the calendar year for all pollutants.

(2) Applies in areas representing generalized atmospheric levels; 20 PPM applies in any other place where members of the public congregate for extended periods of time.

(3) The standards set forth in this regulation for hydrocarbons are not based upon the direct adverse effects of hydrocarbons but upon an empirical relationship, based upon ambient air quality measurements, between morning hydrocarbon concentrations and oxidant concentrations occurring later the same day. The hydrocarbon standard is designed primarily to achieve the standard for photochemical oxidants. In view of the lack of an exact quantitative relationship, the uncertainties in existing measurement techniques and a lack of full identification of the photochemically reactive species of hydrocarbons occurring in the ambient air in the region, these levels should be considered as tentative pending further scientific developments.

(4) Three hour period: 6 a.m. to 9 a.m. Eastern Standard Time.]

10.18.02 Control of Air Pollution in Area I

10.18.03 Control of Air Pollution in Area II

10.18.06 Control of Air Pollution in Area V

10.18.07 Control of Air Pollution in Area VI

.02 Control and Prohibition of Visible Emissions.

[A. For the purpose of these regulations:

(1) "Existing installation or equipment" means those erected before January 17, 1972, or such other date as specified in these regulations.

(2) "Modified installation or equipment" means those altered, changed, or added to on or after January 17, 1972, or such other date as specified in these regulations.

(3) "New Plant" means any installation for which the major proportion of the fuel burning, incineration, processing or manufacturing equipment in the installation was erected on or after January 17, 1972 or such other date as specified in these regulations. This definition is not intended to apply to a "modified installation" or equipment where new control equipment is added to an existing installation. In questionable cases, the determination of new plants shall be made by the Department.]

[B. Visible Emissions from New Plants. A person shall not cause or permit the discharge of emissions from any plant or building erected on or after January 17, 1972, other than water in an uncombined form, which is visible to human observers.]

[C. Visible Emissions from Existing and Modified Installations.

(1) Existing and Modified Bituminous Concrete Manufacturing Plants. A person shall not cause or permit the discharge of emissions from any existing or modified bituminous concrete manufacturing installation other than water in an uncombined form, which are visible to the human observer.

(2) Other Existing and Modified Installation. A person shall not cause or permit emissions from any other existing or modified installation or building that are darker in shade or appearance than that designated as No. 1 on the Ringelmann Smoke Chart or greater than 20 percent opacity.]

A. A person may not cause or permit the discharge of emissions from any installation, other than water in an uncombined form, which is greater than 20 percent opacity.

[D.] *B.* Exceptions.

(1) [§§B and C] *§A* does not apply to emissions during the building of a new fire, cleaning of fires, soot blowing, start-up and process modifications or adjustments, or occasional cleaning of control equipment, which are not [darker in shade or appearance than that designated as No. 2 on the Ringelmann Smoke Chart or not] greater than 40 percent opacity for a period [or periods aggregating no more than 4 minutes in any sixty minutes.] *of no more than 6 consecutive minutes in any 60 minutes.*

[(2) Any person who believes that meeting the requirements of §B is not practical in a particular instance may request an exception to the requirements of §B. Such a request shall be submitted to the Department in writing and include evidence to show why compliance is not practical. Upon the receipt of a request for an exception, the Department shall schedule a public hearing to be held within 60 days. The applicant for the exception shall advertise the hearing prominently at least 30 days prior to the hearing date, by notice in a newspaper of general circulation in the subdivision in which the facility or source for which the exception is sought is located. The notice shall include the name of the facility or source and any additional information the Department may require. Based upon the evidence presented at the hearing the Secretary may grant an exception to §B for a period not to exceed 5 years under other terms and conditions that are appropriate to reduce the impact of the exception.]

(2) Exceptions to Requirements of §A.

(a) Any person who believes that meeting the requirements of §A, above, is not practical or technologically feasible in a particular instance may request an exception to the requirements of §A. The request shall be submitted to the Department in writing and shall include evidence indicating why compliance is not practical or not technologically feasible. Upon receipt of this request, the Department will schedule a public hearing to be held within 60 days to consider the request for an exception. The Department will give at least 30 days notice in the Maryland Register by announcing the purpose, date, time, and place of the hearing. The applicant shall advertise the hearing for the exception prominently at least 30 days before the hearing date by notice in a newspaper of general circulation in the subdivision in which is located the facility or source for which the exception is sought. The notice shall contain the same information as the notice published in the Maryland Register. Based upon the evidence presented in the request and at the public hearing, the Secretary, or his designated hearing officer, will make a finding as to the practicality or technical feasibility of compliance with §A. If the Secretary or his designated hearing officer finds that compliance is not practical or is not technologically feasible, he will grant an exception to §A.

(b) In making his determination, the Secretary or his designated hearing officer will take into consideration all evidence relating to the practicality or technological feasibility of compliance, including evidence of source hardship and economic burden, cost-effectiveness, and social, environmental, and economic consequences.

(c) Upon granting an exception, the Secretary or his designated hearing officer will establish an opacity standard applicable to the building or installation receiving the exception which he finds is practical and technologically feasible. Exceptions may not be granted for a period of more than 5 years, and may be renewed.

(3) (text unchanged)

(4) [Exceptions] The Control Officer may grant exceptions to [paragraph .02C] *§A*, above, under the following conditions.

(a)—(b) (text unchanged)

[E.] *C.*—[F.] *D.* (text unchanged)

.03 Control and Prohibition of Particulate Matter Emissions.

A. (text unchanged)

B. Control of Particulate Matter from Fuel Burning Equipment.

(1) (text unchanged)

(2) [New] *Existing* Fuel Burning Equipment. [(a)] A person may not cause or permit particulate matter caused by the combustion of fuel [oil] in any fuel burning equipment erected [after] *before* January 17, 1972, to be discharged into the atmosphere in excess of the amounts shown in [Table 1] *Figure 1.*

[(b) A person shall not cause or permit particulate matter caused by combustion of solid fuel in any fuel burning equipment erected after January 17, 1972, to be discharged into the atmosphere in excess of the amounts shown in Table 1.]

[(c) Dust collection Devices Required on New Fuel Burning Equipment.

(i) A person shall not cause or permit the combustion of residual fuel oil in any fuel burning equipment erected after January 17, 1972 with a maximum heat input of 13 million BTU/hour (13.7 gigajoules/hour) or more unless such equipment is fitted with a dust collector which is so designed that it reasonably may be expected to produce sufficient dust particle force residence time and particulate retention to satisfy the requirements of Table 1.

(ii) A person shall not cause or permit the combustion of solid fuel in any fuel burning equipment erected after January 17, 1972 unless such equipment is so designed that it reasonably may be expected to produce sufficient dust particle force, residence time and particle retention to satisfy the requirements of Table 1.]

[(3) Existing and Modified Fuel Burning Equipment. A person shall not cause or permit particulate matter caused by the combustion of fuel in existing or modified fuel burning equipment to be discharged from any stack or chimney into the atmosphere in excess of the hourly rate set forth in the following table.

Heat Input in Million BTU Per Hour (Gigajoules Per Hour)	Maximum Allowable Discharge of Particulate Matter in Pounds Per Million BTU (Grams/Gigajoule) from Existing and Modified Fuel Burning Equipment
Up to and Including 10 (10.55)	0.60 (258)
10,000 and Greater (10,550)	0.12 (51.6)

For a heat input between the heat inputs stated in the preceding table, maximum allowable discharge of particulate matter is shown for existing and modified fuel burning equipment in Figure 1. For these purposes, heat input shall be calculated as the aggregate heat content of all fuels whose products of combustion pass through the stack or chimney.]

(3) New Fuel Burning Equipment. A person may not cause or permit particulate matter caused by the combustion of fuel in any fuel-burning equipment erected on or after January 17, 1972, to be discharged from any stack or chimney into the atmosphere in excess of the amounts shown in Figure 2.

(4) Exceptions.

(a) [Interruptible gas service. Fuel burning equipment burning gas with an interruptible gas service is exempt from the provisions of (2) and (3).]

[(b)] The Control Officer may grant exceptions to [paragraph (3)] *§B(2)*, above, under the following conditions:

(i) When the application of [paragraph (3)] *§B(2)* to a residential building housing two or less families creates undue economic hardship on individuals residing therein; or,

(ii) (text unchanged)

[(c)] *(b)* Fuel burning installations on ships are exempt from the provisions of *this regulation.*

C. Particulate Matter from [Incineration Plants and Installations] *Incinerators.*

[(1) Incineration Plants erected on or after January 17, 1972.

(a) A person shall not cause or permit to be discharged into the atmosphere particulate matter to exceed 0.10 gr/SCFD (229 mg/dscm) from any new incinerator plant that has a burning capacity less than 1 ton (907 kilograms) of refuse per hour and is used to burn less than 5 tons (4540 kilograms) of refuse per day.

(b) A person shall not cause or permit to be discharged into the atmosphere particulate matter to exceed 0.03 gr./SCFD (69 mg/dscm) from any new incineration plant other than pathological that has a burning capacity equal to or greater than 1 ton (907 kilograms) of refuse per hour or is used to burn 5 tons (4540 kilograms) or more of refuse per day.

(c) A person shall not cause or permit to be discharged into the atmosphere particulate matter to exceed 0.10 gr/SCFD (229 mg/dscm) from any new pathological incineration plant. Medical waste may be burned in such units, provided that the unit has been approved for that purpose by the Department.]

[(2)] *(1)* Existing [and Modified Incineration Installations] *Incinerators.* A person may not cause or permit to be discharged into the outdoor atmosphere from any [existing or modified] incinerator *erected before January 17, 1972,* the following:

(a) From any existing [or modified] incinerator burning less than 200 pounds (90.7 kilograms) of refuse per hour, particulate matter to exceed .3 gr/SCFD (687 mg/dscm).

(b) From any existing [or modified] incinerator burning 200 (90.7 kilograms) or more pounds of refuse per hour, particulate matter to exceed .2 gr/SCFD (458 mg/dscm).

[(c) From any existing or modified pathological incinerator, particulate matter to exceed .3 gr/SCFD (687 mg/dscm). Medical waste may be burned in such units, provided that the unit has been approved for that purpose by the Department.]

(2) New Incinerators. A person may not cause or permit particulate matter to be discharged from any incinerator erected on or after January 17, 1972, in excess of .10 gr/SCFD (229 mg/dscm).

D. (text unchanged)

[E. Particulate Matter from Other Plants and Installations.]

[(1) Other New Plants Erected on or after January 17, 1972.

(a) A person shall not cause or permit to be discharged into the outdoor atmosphere from any other new process plant, particulate matter in excess of 0.03 gr/SCFD (69 mg/dscm).

(b) The maximum allowable weight of particulate matter discharged per hour from any other new process plant shall not exceed that determined from Table 2. Where the process weight per hour falls between two values in the table, the maximum weight discharged per hour shall be determined by linear interpolation. When the process weight exceeds 60,000 pounds per hour (27,200 kilograms per hour) the maximum allowable weight discharged per hour will be determined by the use of the following equation:

$E = 55.0\, P^{0.11} - 40$ ($E = 11.79\, P^{0.11} - 18.14$

E = Maximum weight discharged per hour (lbs.) E = Maximum weight discharged per hour (kg)

P = Process weight rate in tons per hour P = Process weight in kilograms per hour)

This limitation shall supersede the requirements of subparagraph .03E(1)(a) if it requires a lower emission rate per hour.]

[(2) Other Existing and Modified Process Installations.

(a) Existing and Modified Bituminous Concrete Manufacturing Installations. A person shall not cause or permit to be discharged into the atmosphere from any existing or modified bituminous concrete manufacturing installation particulate matter in excess of 0.03 gr/SCFD (69 mg/dscm).

(b) Other Existing and Modified Installations.

(i) The maximum allowable weight of particulate matter discharged per hour from any other existing or modified process installation shall not exceed that determined from Table 2. Where the process weight per hour falls between two values in the table, the maximum weight discharged per hour shall be determined by linear interpolation. When the process weight exceeds 60,000 pounds per hour (27,200 kilograms per hour) the maximum allowable weight discharged per hour will be determined by use of the following equation:

$E = 55.0\, P^{0.11} - 40$ ($E = 11.79\, P^{0.11} - 18.14$

E = Maximum weight discharged per hour (lbs.) E = Maximum weight discharged per hour (kg)

P = Process weight rate in tons per hour P = Process weight rate in kilograms per hour)

(ii) For those processes in which the process weight per hour exceeds 60,000 pounds (27,200 kilograms) the maximum allowable weight of particulate matter discharged per hour may exceed that calculated by the above equation providing that the concentration of particulate matter in the gases discharged to the atmosphere is less than 0.05 gr/SCFD (115 mg/dscm).]

E. Particulate Matter from Asphalt Concrete Plants. A person may not cause or permit particulate matter to be discharged from any asphalt concrete plant constructed before June 11, 1973, in excess of .05 gr/SCFD (92 kg/dscm).

F. Particulate Matter from Other Installations.

(1) Existing Other Installations. A person may not cause or permit particulate matter to be discharged from any other installation constructed before January 17, 1972, in excess of the values determined from Table 1. If the process weight per hour falls between two values in the table, the maximum weight discharged per hour shall be determined by linear interpolation. If the process weight exceeds 60,000 pounds (27,200 kilograms) per hour, the maximum allowable weight discharged per hour will be determined by the use of the following equation:

$E = 55.0\, P^{0.11} - 40$ ($E = 11.79\, P^{0.11} - 18.14$

E = Maximum weight discharged per hour (lbs.) E = Maximum weight discharged per hour (kg)

P = Process weight in tons per hour P = Process weight in kilograms per hour)

For those processes in which the process weight per hour exceeds 60,000 pounds (27,200 kilograms), the maximum allowable weight of particulate matter discharged per hour may exceed that calculated by the above equation providing that the concentration of particulate matter in the gases discharged to the atmosphere is less than .05 gr/SCFD (115 mg/dscm).

(2) New Other Installations. A person may not cause or permit particulate matter to be discharged from any other installation constructed on or after January 17, 1972, in excess of .05 gr/SCFD (115 kg/dscm).

(3) Exception. For any premise for which the Department determines that compliance with §F(2) will cause or exacerbate a violation of the National Ambient Air Quality Standards or federal Prevention of Significant Deterioration increments, the applicable emission standard is .03 gr/SCFD (229 mg/dscm).

[F.] *G.* (text unchanged)

.04 Control and Prohibition of Gas and Vapor Emissions.

A. (text unchanged)

B. 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 the following limitations:

(1) (text unchanged)

(2) [On and after July 1, 1975, residual] *Residual* fuel oil, 2.0 percent.

(3) Distillate fuel oils, .3 percent.

(4) Process gas used as a fuel, .3 percent.

C. (text unchanged)

D. Exceptions.

(1)—(4) (text unchanged)

(5) For any premise located in Area I, for which the Department determines that compliance with §B(1) and (2), above, will cause or exacerbate a violation of the National Ambient Air Quality Standards or federal Prevention of Significant Deterioration of Air Quality increments, the applicable emission standard is as follows:

(a) For solid fuel, 1.8 pounds oxides of sulfur per million Btu (.75 kilogram per gigajoule) actual heat input per hour.

(b) For residual oil, 1.0 percent sulfur content by weight.

E.—F. (text unchanged)

G. Nitrogen Oxides from New Fuel Burning Equipment.

(1) A person may not cause or permit the discharge of nitrogen oxides into the atmosphere, from any fuel burning equipment built after May 12, 1972, having a heat input rating of 250 million BTU (264 gigajoules) per hour, or more, in excess of the following rates:

(a)—(b) (text unchanged)

(c) [0.50] *.70* pounds per million BTU ([215] *318* gm per gigajoule) heat input, maximum 2-hour average, expressed as NO_2 when solid fuel is burned.

(2) (text unchanged)

H. (text unchanged)

I. Hydrocarbons from Other Than Fuel-Burning Equipment.

(1) Definitions.

(a) (text unchanged)

(b) "True vapor pressure" means the absolute pressure in pounds per square inch (kiloneutons per square meter) determined at storage conditions. Storage conditions shall be taken as the average monthly temperature. If the storage is subject to solar and ambient heat gain only, the temperature shall be taken as the average monthly temperature, to a maximum average of 77°F (25°C) (average storage temperature for the months of May through September). True vapor pressure shall be determined by measurement at the storage conditions or by the use of a nomograph, published by the Coordinating Research Council and include with these regulations as Figure **[**2**]** *3*, relating true vapor pressure to Reid Vapor Pressure and storage temperature.

(2) (text unchanged)

J. (text unchanged)

.06 Control and Prohibition of Installations and Operations.

A.—C. (text unchanged)

D. Prohibition of Certain New Fuel Burning Equipment.

(1) (text unchanged)

(2) A person may not construct fuel burning equipment designed for use of solid fuel in which any individual furnace has a rated heat input of less than **[**50**]** *13* million BTU (**[**52.8**]** *13.7* gigajoules) per hour.

(3)—(4) (text unchanged)

E. (text unchanged)

Table 1: Deleted in its entirety.

Table **[**2**]** *1*.

Table **[**2B**]** *1B*.

Figure 1: Deleted in its entirety.

Figure 1: See following figure.

FIGURE 1

Maximum Allowed Discharge of Particulate Matter From Existing Fuel Burning Equipment (Equipment Built Before January 17, 1972)

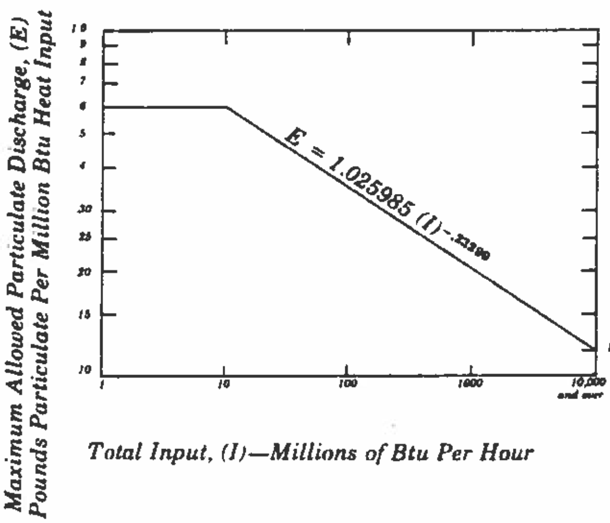
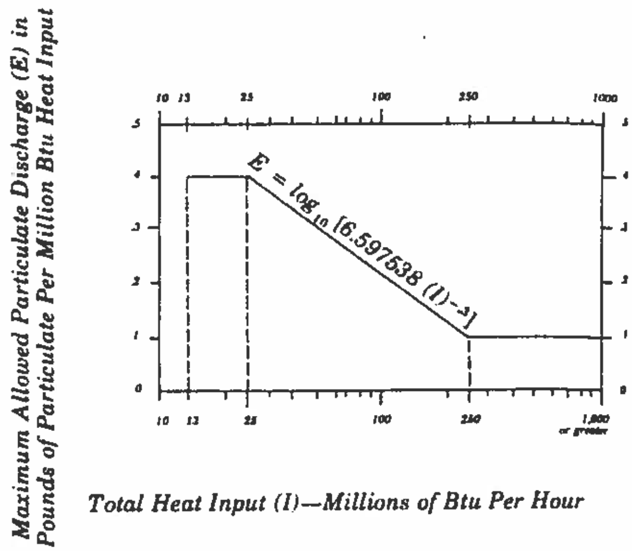


Figure 2: See following figure.

FIGURE 2

Maximum Allowed Discharge of Particulate Matter From New Fuel Burning Equipment (Equipment built after January 17, 1972)



Notes: 1. The construction of new solid and residual oil fuel burning equipment under 13 MM Btu (13.7 gigajoules) per hour is prohibited under COMAR 10.18.02.06D, 10.18.03.06D, 10.18.06.06D, and 10.18.07.06D.

2. New fuel burning equipment over 250 MM Btu (263.8 gigajoules) per hour are regulated by NSPS source regulations COMAR 10.18.02.05, 10.18.03.05, 10.18.06.05, and 10.18.07.05.

3. Depending on load factor, fuel ash content and control equipment, fuel burning equipment which has a heat input greater than approximately 25 MM Btu (26.4 gigajoules) per hour may be subject to Prevention of Significant Deterioration Review (40 USC Part 52.21) and consequent additional control requirements.

Figure **[**2.**]** *3*.

10.18.04 Control of Air Pollution in Area III

10.18.05 Control of Air Pollution in Area IV

.04 Control and Prohibition of Gas and Vapor Emissions.

A. (text unchanged)

B. 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 the following limitations.

(1)—(3) (text unchanged)

[(4) On and after July 1, 1980, residual fuel oil, 0.5 percent.**]**

[(5)] *(4)* Sulfur Content Limitations For Coke Ovens.
(a)—(c) (text unchanged)
[(d) After June 30, 1983, the plant-wide average in any 2-hour period, of the sulfur content by weight of coke oven gas used as fuel from coke ovens constructed before the effective date of this regulation, may not exceed that permitted in residual fuel oils.]
C.—F. (text unchanged)
G. Nitrogen Oxides from Fuel Burning Equipment.
(1) New Fuel Burning Equipment Erected On or After May 12, 1972. A person may not cause or permit the discharge of nitrogen oxides into the atmosphere, from any new fuel burning equipment having a heat input rating of 250 million BTU (264 gigajoules) per hour or more, in excess of the following rates:
(a)—(b) (text unchanged)
(c) [0.50] *.70* pounds ([215] *318* gm) per million BTU (gigajoules) heat input maximum 2-hour average, expressed as NO_2 when solid fuel is burned.
(2)—(3) (text unchanged)
H.—K. (text unchanged)

CHARLES R. BUCK, JR.
Secretary
Department of Health and Mental Hygiene

[Md. R. Doc. No. 79-696. Filed at Div. of St. Doc. Apr. 23, 1979. Filed at AELR Comm. Apr. 24, 1979.]

Subtitle 19 DANGEROUS DEVICES AND SUBSTANCES

10.19.04 Prescription Drugs—Products Selection

Authority: Article 43, §273A, Annotated Code of Maryland

Notice of Proposed Action

The Environmental Health Administration proposes to adopt the amendment to Regulation **.02 Interchangeable Drug Products,** printed below, to be effective in August, 1979.

These regulations prohibit the substitution or interchanging of a critical-dose drug, tolbutamide tablets.

Estimate of Economic Impact

The proposed action has no economic impact.

Opportunity for Public Comment

The Environmental Health Administration will hold a hearing concerning the adoption of these regulations August 1, 1979, 9:30 a.m., in the 3rd Floor Conference Room, 201 West Preston Baltimore, Maryland 21201. All interested persons are invited to attend and give their views.

Written comments may be sent to Raymond A. Huber, Regulations Coordinator, O'Conor Building, Room 314-A, 201 West Preston Street, Baltimore, Maryland 21201. These comments must be received no later than the date of the hearing.

.02 Interchangeable Drug Products.
A.—PPP. (text unchanged)
QQQ. Tolbutamide Tablets.

	[500 mg.]	[Promo Pharm.]
Orinase	500 mg.	Upjohn

RRR.—XXX. (text unchanged)

CHARLES R. BUCK, JR.
Secretary
Department of Health and Mental Hygiene

[Md. R. Doc. No. 79-634. Filed at Div. of St. Doc. Apr. 12, 1979. Filed at AELR Comm. Apr. 12, 1979.]

Title 11 DEPARTMENT OF TRANSPORTATION

Subtitle 01 OFFICE OF THE SECRETARY

11.01.06 Transportation Planning Process

Authority: Transportation Article, §2-103, Federal-Aid Highway Program Manual, Volume 7, Chapter 7, §1, promulgated under authority of §109(h), Title 23, U.S.C.

Notice of Proposed Action

The Department of Transportation proposes to adopt the amendment printed below to the "Maryland Action Plan, Revised Chapter V—Highway Project Development (Maryland Department of Transportation, April, 1977)", under **COMAR 11.01.06.01, The "Action Plan"**, to be effective on June 29, 1979. Specifically, the Department is proposing to amend Chapter V, Section E—Project Design (Phase III & IV), R/W Relocation Assistance Statement Approval. This change would remove a self-imposed requirement for Federal Highway Administration approval of pre-acquisition relocation plan design approval.

Estimate of Economic Impact

The proposed action has no economic impact.

Opportunity for Public Comment

No public hearing is scheduled. Interested parties may submit views or comments to Gary L. Rosenbaum, Office of Transportation Planning, Department of Transportation, P.O. Box 8755, Baltimore-Washington International Airport, Maryland 21240, on or before June 5, 1979.

.01 The "Action Plan."

Ed. Note. Pursuant to Article 41, §256H(a), Annotated Code of Maryland, "Maryland Action Plan, Revised Chapter V, Highway Project Development (Maryland Department of Transportation, April 1977)" was incorporated by reference at 4:26 Md. R. 2025 (December 16, 1977). A copy of this document is filed at each of the public repositories listed in 5:16 Md. R. 1303—1306 (August 11, 1978) and at the Division of State Documents, 11 Bladen Street, Annapolis, Maryland.

Subtitle 22 BOARD OF COSMETOLOGISTS

09.22.01 Types of Licensure: Privileges of and Limitations on Licensees

Authority: Article 43, §544,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 3, 1979, an amendment to Regulation .15 under **COMAR 09.22.01 Types of Licensure: Privileges of and Limitations on Licensees,** was adopted by the State Board of Cosmetologists.

This amendment, which was proposed for adoption in 6:11 Md. R. 984 (June 1, 1979), has been adopted as proposed. This becomes effective coincident with the date of this issue of the Maryland Register.

EUNICE R. ALPER
Executive Director

[Md. R. Doc. No. 79-1686. Filed at Div. of St. Doc. Oct. 9, 1979.]

Subtitle 22 BOARD OF COSMETOLOGISTS

09.22.02 Schools of Beauty Culture—Types of Licensure, Application, Requirements, Curriculum, Limitations on Licensees

Authority: Article 43, §536(e) and 544,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 3, 1979, amendments to Regulation .16, .19, and .20, under **COMAR 09.22.02 Schools of Beauty Culture—Types of Licensure, Application, Requirements, Curriculum, Limitations on Licensees,** were adopted by the State Board of Cosmetologists.

These amendments, which were proposed for adoption in 6:11 Md. R. 984—985 (June 1, 1979) have been adopted as proposed. They become effective coincident with the date of this issue of the Maryland Register.

EUNICE R. ALPER
Executive Director

[Md. R. Doc. No. 79-1685. Filed at Div. of St. Doc. Oct. 9, 1979.]

Title 10
DEPARTMENT OF HEALTH AND MENTAL HYGIENE

Subtitle 18 AIR QUALITY

10.18.01 Control of Air Pollution in the State

10.18.02 Air Pollution in Area I

10.18.03 Air Pollution in Area II

10.18.04 Air Pollution in Area III

10.18.05 Air Pollution in Area IV

10.18.06 Air Pollution in Area V

10.18.07 Air Pollution in Area VI

Authority: Article 43, §§690 through 706,
Annotated Code of Maryland

Notice is given that on October 9, 1979, amendments to Regulation **.03 Air Pollution Episode System,** and Regulation **.04 Ambient Air Quality Standards,** under **COMAR 10.18.01 Control of Air Pollution in the State;** Regulations **.02 Control and Prohibition of Visible Emissions, .04 Control and Prohibition of Gas and Vapor Emissions,** and **.06 Control and Prohibition of Certain New Fuel Burning Equipment** under **COMAR 10.18.02 Air Pollution in Area I, COMAR 10.18.03 Air Pollution in Area II, COMAR 10.18.06 Air Pollution in Area V,** and **COMAR 10.18.07 Air Pollution in Area VI;** and Regulation **.04 Control and Prohibition of Gas and Vapor Emissions,** under **COMAR 10.18.04 Air Pollution in Area III,** and **COMAR 10.18.05 Air Pollution in Area IV;** were adopted by the Department of Health and Mental Hygiene, Charles R. Buck, Jr., Secretary.

These amendments which were proposed for adoption in 6:9 Md. R. 739—747 (May 4, 1979), have been adopted as proposed and will become effective on December 10, 1979.

In the notice of hearing which appeared in 6:9 Md. R. 739 (May 4, 1979), eight companies were identified that would not be permitted to take advantage of the proposed relaxation to the sulfur in fuel content and four companies were identified that would not be permitted to take advantage of the proposed relaxation to the particulate emissions standard. Based on the information presented at the hearings, those lists have been modified. The following sources will be required to continue burning 1 percent sulfur fuels: Celanese Corporation; Kelly-Springfield Tire Company; Potomac Edison Company; Fairchild Republic; Mack Trucks, Inc. The following sources will be required to continue meeting the particulate emissions standard of 0.03 gr/SCFD: Kelly-Springfield Company (buffers, tire tread grinders); Eastalco Aluminum Company (potline electro-cells, carbon anode furnace); D. M. Stoltzfus and Sons (stone crushing).

CHARLES R. BUCK, JR.
Secretary of Health and Mental Hygiene

[Md. R. Doc. No. 79-1710. Filed at Div. of St. Doc. Oct. 10, 1979.]

Title 10 DEPARTMENT OF HEALTH AND MENTAL HYGIENE

Subtitle 27 BOARD OF EXAMINERS OF NURSES

10.27.06 Practice of Nurse Anesthetist

Authority: Article 43, §290—302,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 10, 1979, Regulations .01—.09, under **COMAR 10.27.06 Practice of Nurse Anesthetist,** were adopted by the Secretary of the Department of Health and Mental Hygiene.

These regulations, which were proposed for adoption in 6:2 Md. R. 87—88 (January 26, 1979), have been adopted as proposed. They become effective December 1, 1979.

CHARLES R. BUCK, JR.
Secretary of Health and Mental Hygiene

[Md. R. Doc. No. 79-1705.]

Title 11 DEPARTMENT OF TRANSPORTATION

Subtitle 01 OFFICE OF THE SECRETARY

11.01.11 Small Business Procurements, Construction Contracts

Authority: Article 41, §231, G-2,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 1, 1979, amendments to Regulations **.02 Definitions, .03 Small Business Contractor List,** and **.04 Small Business Set-aside,** under **COMAR 11.01.11 Small Business Procurements, Construction Contracts,** were adopted by the Secretary of Transportation.

These amendments, which were proposed for adoption in 6:16 Md. R. 1351—1352 (August 10, 1979), have been adopted as proposed. They become effective coincident with the date of this issue of the Maryland Register.

JAMES J. O'DONNELL
Secretary of Transportation

[Md. R. Doc. No. 79-1647. Filed at Div. of St. Doc. Oct. 2, 1979.]

Subtitle 03 STATE AVIATION ADMINISTRATION

11.03.04 Aeroneautical Regulations

Authority: Transportation Article, §5-204(d)(4),
and Chapter 190, Acts of 1976,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on September 11, 1979, amendments to Regulations .05, .10, and .11, under **COMAR 11.03.04 Aeronautical Regulations,** were adopted by the State Aviation Administrator.

These amendments, which were proposed for adoption in 6:15 Md. R. 1290 (July 27, 1979), have been adopted as proposed. They become effective coincident with the date of this issue of the Maryland Register.

KARL R. SATTLER
State Aviation Administrator

[Md. R. Doc. No. 79-1637. Filed at Div. of St. Doc. Sept. 28, 1979.]

Subtitle 04 STATE HIGHWAY ADMINISTRATION

11.04.09 Bicycles

Authority: Transportation Article, §21-1205.1(b)(3),
Annotated Code of Maryland

Notice of Final Action

Notice is given that on September 25, 1979, new Regulation **.01 Smooth Surface,** under **COMAR 11.04.09 Bicycles,** was adopted by the Administrator of the State Highway Administration.

This new regulation, which was proposed for adoption in 6:16 Md. R. 1352 (August 10, 1979), has been adopted as proposed. It becomes effective coincident with the date of this issue of the Maryland Register.

M. S. CALTRIDER
State Highway Administrator

[Md. R. Doc. No. 79-1633. Filed at Div. of St. Doc. Sept. 27, 1979.]

SECTION 2. AND BE IT FURTHER ENACTED, That this Act shall take effect July 1, 1978.

Approved May 29, 1978.

CHAPTER 1005

(House Bill 1168)

AN ACT concerning

Air Quality Control Standards

FOR the purpose of ~~providing utility bill savings to Maryland citizens while maintaining air quality at levels fully adequate to protect the health, general welfare, and property of the people of the State;~~ requiring certain regulations of the Department of Health and Mental Hygiene governing ambient air quality to be identical to national air quality standards; requiring that certain emission standards be established for certain stationary sources; <u>and</u> providing a transition period for the promulgation of regulations ~~; and requiring that all fuel cost savings consequently realized by public service companies be fully applied to reduce electric bills rendered to customers.~~

BY repealing

Article 43 – Health
Section 693(b)
Annotated Code of Maryland
(1971 Replacement Volume and 1977 Supplement)

BY adding to

Article 43 – Health
Section 691(h) and (i), and 693(b)
Annotated Code of Maryland
(1971 Replacement Volume and 1977 Supplement)

SECTION 1. BE IT ENACTED BY THE GENERAL ASSEMBLY OF MARYLAND, That section(s) of the Annotated Code of Maryland be repealed, amended, or enacted to read as follows:

Article 43 – Health

691.

For the purposes of this Subtitle:

(H) "EMISSION STANDARD" MEANS A REQUIREMENT WHICH LIMITS THE QUANTITY, QUALITY, RATE, OR CONCENTRATION OF EMISSIONS FROM A SOURCE , INCLUDING REQUIREMENTS RELATING TO THE OPERATION OR MAINTENANCE OF THE SOURCE TO ASSURE CONTINUOUS EMISSION REDUCTION.

(I) "SECRETARY" MEANS THE SECRETARY OF HEALTH AND MENTAL HYGIENE.

693.

[(b) The Department shall prepare and submit to the Board for approval not later than June 1, 1968, regulations establishing standards for emissions into the air and the ambient air quality for each of the areas authorized by subsection (a) of this section.

The governing body of any local jurisdiction within any area may request the Department to recommend to the Board for adoption a regulation establishing more restrictive standards for emissions or ambient air quality to be applicable within its geographic area.]

(B) (1) THE DEPARTMENT SHALL ~~PREPARE AND SUBMIT TO THE BOARD FOR APPROVAL~~ PROMULGATE REGULATIONS ESTABLISHING STANDARDS FOR EMISSIONS INTO THE AIR AND THE AMBIENT AIR QUALITY FOR EACH OF THE AREAS AUTHORIZED BY SUBSECTION (A) OF THIS SECTION.

(2) THE GOVERNING BODY OF ANY LOCAL JURISDICTION WITHIN ANY AREA MAY REQUEST THE DEPARTMENT TO ADOPT MORE RESTRICTIVE STANDARDS FOR EMISSIONS OR AMBIENT AIR QUALITY TO BE APPLICABLE WITHIN ITS GEOGRAPHIC AREA.

(3) WITH REGARD TO AMBIENT AIR QUALITY, EXCEPT AS PROVIDED IN §693(B)(2), STANDARDS FOR POLLUTANTS SHALL BE ESTABLISHED BY THE DEPARTMENT AND SHALL BE IDENTICAL TO THE STANDARDS FOR POLLUTANTS FOR WHICH NATIONAL PRIMARY OR SECONDARY AMBIENT AIR QUALITY STANDARDS ARE PRESCRIBED AND ADOPTED BY THE FEDERAL ENVIRONMENTAL PROTECTION AGENCY OR ANY OTHER FEDERAL AGENCY ACTING PURSUANT TO §109 ET. SEQ. OF THE FEDERAL CLEAN AIR ACT OR OTHER APPLICABLE FEDERAL LEGISLATION.

(4) THE DEPARTMENT IN ORDER TO PROTECT THE HEALTH, GENERAL WELFARE, AND PROPERTY OF THE PEOPLE OF THE STATE MAY ESTABLISH AMBIENT AIR QUALITY STANDARDS FOR SUBSTANCES FOR WHICH NO NATIONAL AMBIENT AIR QUALITY STANDARDS HAVE BEEN PROMULGATED. STATE AMBIENT AIR QUALITY STANDARDS MAY INCLUDE MAXIMUM CONCENTRATION OF POLLUTANTS IN SUBSTANCES OTHER THAN AIR IF THE SECRETARY DETERMINES THAT TRANSPORTATION THROUGH THE AIR IS A SIGNIFICANT FACTOR IN THE BUILDUP OF THE POLLUTANT IN THE SUBSTANCE AND IF THE SECRETARY DETERMINES THAT MONITORING OF THE SUBSTANCE OTHER THAN AIR FACILITATES THE CONTROL OF THE POLLUTANT.

(5) ALL AMBIENT AIR QUALITY STANDARDS PREVIOUSLY PROMULGATED WHICH ARE INCONSISTENT WITH THIS

REQUIREMENT ARE REPEALED TO THE EXTENT OF THE INCONSISTENCY.

(6) ~~FOR~~ EXCEPT AS PROVIDED IN PARAGRAPH (2) OF THIS SUBSECTION (B), FOR AREAS WHERE ATTAINMENT OF AMBIENT AIR QUALITY STANDARDS HAS BEEN ACHIEVED THE ESTABLISHING OF STATE EMISSION STANDARDS SHALL BE BASED ON THE GOAL OF ACHIEVING EMISSION LEVELS WHICH ARE NO MORE RESTRICTIVE THAN REQUIRED TO ATTAIN AND MAINTAIN THE AMBIENT AIR QUALITY STANDARDS REVISED PURSUANT TO PARAGRAPH (3) OF THIS SUBSECTION (B), EXCEPT WHERE NEW SOURCE PERFORMANCE STANDARDS ~~OR~~, NATIONAL PREVENTION OF SIGNIFICANT DETERIORATION ~~STANDARDS~~ REQUIREMENTS, OR NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS , OR ANY OTHER REQUIREMENTS OF THE FEDERAL CLEAN AIR ACT ARE APPLICABLE.

(7) FOR THOSE EMISSIONS FOR WHICH NO AMBIENT AIR QUALITY STANDARDS HAVE BEEN ADOPTED PURSUANT TO PARAGRAPH (3) OF THIS SUBSECTION (B), ~~SUCH AS VISIBLE EMISSIONS AND ODORS,~~ THE SECRETARY MAY ESTABLISH EMISSION STANDARDS AND REQUIREMENTS FOR ABATEMENT OF AIR POLLUTION FOR THE VARIOUS CLASSES OF SOURCES.

(8) ALL EMISSION REGULATIONS PREVIOUSLY PROMULGATED WHICH ARE INCONSISTENT WITH ~~THESE REQUIREMENTS~~ PARAGRAPH (6) OF THIS SUBSECTION (B) SHALL BE REPEALED TO THE EXTENT OF THE INCONSISTENCY NOT LATER THAN JULY 1, 1979.

~~(9) ALL SAVINGS IN FUEL COSTS WHICH ARE REALIZED BY MARYLAND PUBLIC SERVICE COMPANIES DUE TO REVISED AMBIENT AIR QUALITY STANDARDS AND REVISED AIR EMISSION STANDARDS SHALL BE APPLIED IN TOTO TO REDUCE UTILITY BILLS RENDERED TO CONSUMERS IN ACCORDANCE WITH ARTICLE 78, §54D. THE MECHANISM EMPLOYED FOR THIS PURPOSE SHALL BE THE FUEL RATE ADJUSTMENT CLAUSE IN TARIFFS FILED BY EACH UTILITY COMPANY WITH THE PUBLIC SERVICE COMMISSION.~~

SECTION 2. AND BE IT FURTHER ENACTED, That this Act shall take effect July 1, 1978.

Approved May 29, 1978.

CHAPTER 1006

(House Bill 1326)

AN ACT concerning

Public Information Act

FOR the purpose of eliminating unnecessary definitions; adding and revising definitions; providing a policy statement; ~~allowing~~ ~~directing~~ providing that State and local governments ~~to~~ may maintain only necessary and relevant information about persons under certain

~~22~~ companies (8)
57 pieces (25)

8 not allowed (25-g)
1 not in compliance (3-g)

TABLE II List of Amendment Affected Sources

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF[1] 0.1%	OIL GR	MBTU /HR	CONTROL EQUIP[2]	SO2 LBS/HR	SO2 LBS/D	SO2 TONS/YR	HRS /D	DAYS /YR	STACK HT-FT[3]
1	219 604	11	WESTVACO	O	5	70	8	6	338		163.71	3929.0	667.94	24	340	600
1	219 604	11	WESTVACO	C	18	0	30	0	590	ESP	1838.42	44122.1	7500.75	24	340	600
1	219 604	11	WESTVACO	C	19	0	24	0	785	MCY ESP	2281.25	54750.0	9307.50	24	340	600
1	304 666	13	CELANESE CORPORATION	G	53	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	13	CELANESE CORPORATION	G	54	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	13	CELANESE CORPORATION	G	55	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	13	CELANESE CORPORATION	G	56	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	14	KELLY-SPRINGFIELD TIRE	O	2	0	8	6	135		60.44	1450.6	226.29	24	312	200
1	304 666	14	KELLY-SPRINGFIELD TIRE	C	108	49	15	6	180	ESP	565.44	13570.6	2117.01	24	312	262
1	304 666	14	KELLY-SPRINGFIELD TIRE	C	109	49	15	6	180	ESP	565.44	13570.6	2117.01	24	312	262
1	310 643	5	PPG INDUSTRIES, INC.	C	10	56	10	0	64	MCY	41.83	1003.9	183.22	24	365	100
1	310 643	5	PPG INDUSTRIES, INC.	C	11	56	10	0	64	MCY	41.83	1003.9	183.22	24	365	100
1	310 643	5	PPG INDUSTRIES, INC.	C	12	56	10	0	64		8.67	208.1	37.97	24	365	100
21	568 644	5	POTOMAC EDISON CO.	C	5	0	10	0	382	ESP	224.87	5396.9	971.44	24	360	177
21	568 644	5	POTOMAC EDISON CO.	C	6	71	10	0	710	ESP	1364.05	32737.2	5892.70	24	360	201
21	568 664	75	BYRON, W.D. & SONS	O	103	71	8	6	25		31.39	251.1	31.39	8	250	~~100~~ 150
21	568 664	75	BYRON, W.D. & SONS	O	104	71	8	6	25		31.39	251.1	31.39	8	250	~~100~~ 150
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	C	51	65	10	0	36	MCY	25.70	77.1	6.94	3	180	50
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	C	52	65	10	0	86	MCY	425.83	1277.5	114.97	3	180	50
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	C	53	65	10	0	100	MCY	385.27	1155.8	104.02	3	180	50
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	O	141	65	8	5	3		6.77	20.3	1.83	3	180	1
21	597 659	13	ROPER EASTERN	O	9	0	8	5	21		6.84	54.7	7.11	8	260	30
21	597 659	17	VICTOR HOSIERY CORP.	O	16	68	8	5	9		8.60	68.8	8.94	8	260	30
21	597 659	22	COLOMBO INC.	O	20	65	8	6	8		.35	2.8	.36	8	260	1
21	597 659	22	COLOMBO INC.	O	21	65	8	6	8		.35	2.8	.36	8	260	1
21	597 659	23	MANBECK BREAD CO.	O	22	0	8	4	6		1.40	11.2	1.46	8	260	1
21	597 659	72	MARYLAND MACHINE & FOUNDRY	O	76	58	8	4	1		.70	5.6	.73	8	260	30
21	597 659	90	GRAY CONCRETE	O	86	51	8	4	6		3.21	25.7	3.29	8	256	30
21	597 659	91	BEACHLEY FURNITURE	O	87	68	8	4	8		1.05	8.4	1.09	8	260	30
21	597 659	125	HAGERSTOWN POST OFFICE	O	135	65	8	5	2		3.37	10.1	.91	3	180	50
21	597 659	130	HAGERSTOWN MUNICIPAL LT. PLANT *	O	144	0	8	6	60		.14	1.1	.18	8	315	50
21	597 659	130	HAGERSTOWN MUNICIPAL LT. PLANT *	O	162	57	10	6	195	MCY	101.15	2427.6	382.35	24	315	150
21	597 659	130	HAGERSTOWN MUNICIPAL LT. PLANT *	O	163	57	10	6	195	MCY	101.15	2427.6	382.35	24	315	150
21	597 662	84	JAMISON DOOR - MAPLE AVE.	O	83	56	8	5	4		5.63	45.0	5.86	8	260	1
21	597 682	104	FAIRCHILD REPUBLIC	O	95	41	8	6	19	MCY	7.76	124.2	15.52	16	250	50
21	597 682	104	FAIRCHILD REPUBLIC	O	96	41	8	6	19	MCY	7.76	124.2	15.52	16	250	50
21	597 682	104	FAIRCHILD REPUBLIC	O	97	44	8	6	40	MCY	15.97	255.5	31.94	16	250	50
21	597 682	104	FAIRCHILD REPUBLIC	O	98	44	8	6	40	MCY	15.97	255.5	31.94	16	250	50
21	600 660	6	MACK TRUCKS	O	6	0	8	6	140		19.65	157.2	20.44	8	260	50
21	600 660	6	MACK TRUCKS	O	7	0	8	6	140		19.65	157.2	20.44	8	260	50

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CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF[1] 0.1%	OIL GR	MBTU /HR	CONTROL EQUIP	SO2 LBS/HR	SO2 LBS/D	SO2 TONS/YR	HRS /D	DAYS /YR	STACK HT-FT
21	600 660	6	MACK TRUCKS	0	8	0	8	6	140		19.65	157.2	20.44	8	260	50
21	600 660	74	GILBERT INDUSTRIES	0	78	62	8	4	5		4.38	35.0	4.38	8	250	30
21	602 656	99	SUPREME CONCRETE BLOCK	0	92	61	8	5	5		5.98	47.8	6.22	8	260	30
21	639 664	1	DOUBLEDAY & CO.	0	1	0	8	6	3		1.71	27.4	3.46	16	253	28
21	639 664	1	DOUBLEDAY & CO.	0	2	0	8	6	3		1.71	27.4	3.46	16	253	28
21	662 684	123	FORT RITCHIE	0	109	60	8	5	5		5.40	16.2	1.46	3	180	50
21	662 684	123	FORT RITCHIE	0	110	60	8	5	5		5.40	16.2	1.46	3	180	50
21	662 684	123	FORT RITCHIE	0	111	67	8	5	3		6.77	20.3	1.83	3	180	30
21	662 684	123	FORT RITCHIE	0	112	64	8	5	3		4.07	12.2	1.10	3	180	30
21	662 684	123	FORT RITCHIE	0	113	64	8	5	2		5.40	16.2	1.46	3	180	30
21	662 684	123	FORT RITCHIE	0	115	57	8	5	6		10.80	32.4	2.92	3	180	50
21	662 684	123	FORT RITCHIE	0	116	57	8	5	8		4.07	12.2	1.10	3	180	50
21	662 684	123	FORT RITCHIE	0	119	57	8	5	4		8.80	26.4	2.38	3	180	50
21	662 684	123	FORT RITCHIE	0	120	57	8	5	4		3.37	10.1	.91	3	180	50
21	662 684	123	FORT RITCHIE	0	122	57	8	5	4		3.37	10.1	.91	3	180	30
21	662 684	123	FORT RITCHIE	0	124	57	8	5	9		14.87	44.6	4.01	3	180	50
21	662 684	123	FORT RITCHIE	0	125	66	8	5	4		7.43	22.3	2.01	3	180	30

NOTE:

1. O: Oil-burning equipment, C: Coal-burning equipment, G: Gas-burning equipment
2. ESP: Electrostatic precipitator, MCY: Multicyclone
3. 1:0-30'

* Not in operation at present

CO	ND GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF[1] 0.1%	OIL GR	MBTU /HR	CONTROL[2] EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK[3] HT-FT
1	219 604	11	WESTVACO	P	32	72	0	0	0	DIS	21.47	515.3	87.60	24	340	200
1	219 604	11	WESTVACO	P	33	72	0	0	0	DIS	21.47	515.3	87.60	24	340	200
1	271 683	149	MT. SAVAGE SPECIAL REFRACTORIES	P	31	76	0	0	0	BAG	.22	1.8	.18	8	200	0
1	286 666	101	INTERSTATE ANIESITE CORP. (A)	P	12	71	3	0	0	BAG	3.42 ~~.43~~	~~3.4~~ 27.4	~~.34~~ 2.74	8	200	30
1	304 666	13	CELANESE CORPORATION	P	63	75	0	0	0	BAG	1.29	31.0	5.65	24	365	50
1	304 666	13	CELANESE CORPORATION	P	66	75	0	0	0	BAG	1.29	31.0	5.65	24	365	50
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	60	73	0	0	0	SPR	.06	1.4	.19	24	260	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	69	76	0	0	0	SCR	.83	19.9	3.11	24	312	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	70	77	0	0	0	CYC	.05	1.2	.19	24	312	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	71	77	0	0	0	CYC	.83	19.9	3.11	24	312	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	72	77	0	0	0	CYC	.83	19.9	3.11	24	312	0
1	304 666	29	CUMBERLAND CONTRACTING COMPANY (A)	P	10	0	3	0	0	SCR	4.6 ~~5.07~~	~~40.6~~ 32.4	~~.65~~ 2.9	8	180	30
1	304 666	90	LILLER BROTHERS ASPHALT COMPANY (A)	P	11	70	2	0	0	MCY	6.69 ~~.84~~	~~6.7~~ 53.5	~~.50~~ 4.01	8	150	30
11	120 582	2	GARRETT COUNTY ROADS ASPHALT PLANT (A)	P	23	75	3	0	0	BAG	.67	5.4	.54	8	200	30
11	120 582	34	BROWNING FOODLAND	I	2	73	0	0	0		.46	2.3	.36	5	312	49
11	149 615	3	LAUREL FORK CO. (A)	P	22	61	3	0	0	SCR	4.28 ~~.53~~	~~4.2~~ 34.2	~~.34~~ 2.74	8	160	30
21	467 682	131	RALOC	P	90	73	0	0	0	BAG	.18	1.4	.18	8	250	0
21	467 682	131	RALOC	P	91	73	0	0	0	BAG	.55	4.4	.55	8	250	0
21	467 682	131	RALOC	P	93	73	0	0	0	BAG	.36	2.9	.36	8	250	0
21	558 655	115	MARTIN MARRIETTA - PINESBURG	P	24	73	0	0	0	BAG	.55	4.4	.55	8	250	0
21	558 655	115	MARTIN MARRIETTA - PINESBURG	P	31	73	0	0	0	BAG	.55	4.4	.55	8	250	0
21	568 664	75	BYRON, W.D. & SON	I	30	77	0	0	0		.15	3.6	.56	24	312	37
21	595 650	155	CONSERVIT, INC.	P	35	75	0	0	0	CYC	7.76	62.1	6.21	8	200	0
21	597 659	8	MARQUETTE CEMENT	P	87	77	0	0	0	BAG	3.08	73.9	13.49	24	365	100
21	597 659	8	MARQUETTE CEMENT	P	88	77	0	0	0	BAG	1.75	42.0	7.66	24	365	100
21	597 659	8	MARQUETTE CEMENT	P	89	77	0	0	0	BAG	.42	10.1	1.84	24	365	100
21	597 659	114	CRAIG, O.O. (A)	P	19	63	3	0	0	SCR	1.27	10.2	1.45	8	286	1
21	597 659	114	CRAIG, O.O. (A)	P	36	78	3	2	0	BAG	.97	7.8	1.09	8	280	30
21	597 659	132	BLAINE WINDOW HARDWARE	P	95	74	0	0	0	BAG	.18	1.4	.18	8	250	1
21	597 659	132	BLAINE WINDOW HARDWARE	P	96	74	0	0	0	BAG	.18	1.4	.18	8	250	1
21	597 659	132	BLAINE WINDOW HARDWARE	P	97	74	0	0	0	BAG	.18	1.4	.18	8	250	0
21	597 659	132	BLAINE WINDOW HARDWARE	P	98	74	0	0	0	BAG	.18	1.4	.18	8	250	0
21	598 662	67	BESTER-LONG, INC. (A)	P	111	76	0	0	0	SCR	3.53 ~~.44~~	~~3.5~~ 28.2	~~.35~~ 3.11	8	220	1
21	598 662	67	BESTER-LONG, INC. (A)	P	112	76	0	0	0	SCR	2.10 ~~.26~~	~~2.1~~ 16.8	~~.23~~ 1.85	8	220	30
21	616 610	96	KLINE, RICHARD F. INC.-BOONSBORO (A)	P	67	64	8	0	0	SCR	6.38 ~~.80~~	~~6.4~~ 51.0	~~.32~~ 2.55	8	100	50
21	631 657	107	PLUMMER CONSTRUCTION CO. (A)	P	76	69	2	0	0	BAG	2.28 ~~.29~~	~~2.3~~ 18.2	~~.19~~ 1.46	8	160	30

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF[2] 0.1%	OIL GR	MBTU /HR	CONTROL[2] EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK[3] HT-FT
10	640 610	106	MYERSVILLE SCHOOL	I	36	72	0	0	0	BUR	1.33	4.0	.36	3	180	30
10	650 587	149	MIDDLETOWN MIDDLE SCHOOL	I	48	76	0	0	0	BUR	.51 ~~1.50~~	203 ~~6.02~~	.18 ~~.54~~	4	180	4
10	677 583	131	FORT DETRICK	I	49	76	0	0	0	SCR	2.63	42.1	5.47	~~16~~ (7)	260	60 decrease waste
10	677 583	131	FORT DETRICK	I	50	76	0	0	0	SCR	2.63	42.1	5.47	~~16~~ (7)	260	60
10	678 546	5	EASTALCO ALUMINUM	P	53	75	0	0	0	BAG	60.71	1457.0	265.91	24	365	30
10	678 546	5	EASTALCO ALUMINUM	P	54	75	0	0	0	BAG	60.71	1457.0	265.91	24	365	30
10	678 546	5	EASTALCO ALUMINUM	P	64	75	8	0	0	SCR	8.87	212.9	38.85	24	365	30
10	685 576	26	ETZLER, N.W., CO.	P	34	73	0	0	0	BAG	2.97	23.8	2.38	8	200	50
10	685 576	29	CAMPBELL-GROVE,FRED,PLANT1	P	7	78 69	0	0	0	BAG	.44	10.6	1.65	24	312	1
10	685 576	29	CAMPBELL-GROVE,FRED,PLANT1	P	11	72	0	0	0	BAG	.83	19.9	2.19	24	220	30
10	685 576	29	CAMPBELL-GROVE,FRED,PLANT1	P	18	72	0	0	0	OTH	7.02	112.3	16.06	16	286	0
10	685 576	37	KLINE, RICHARD F., INC. (A)	P	33	73	8	0	0	BAG	6.16	49.3	4.93	8	200	30
10	685 576	78	NORTH FREDERICK ELEMENTARY	I	57	77	0	0	0	BUR	.50	2.0	.18	4	180	4
10	689 652	81	THURMONT ELEM.	I	19	76	0	0	0	BUR	1.53	6.1	.55	4	180	4
10	700 544	83	URBANA ELEM.	I	53	76	0	0	0	BUR	.50	2.0	.18	4	180	4
10	701 601	160	WALKERSVILLE HIGH SCHOOL	I	54	76	0	0	0	BUR	.50	2.0	.18	4	180	4
10	708 682	66	EMMITSBURG ELEM.	I	46	74	0	0	0	BUR	.50	2.0	.18	4	180	4
10	712 627	51	MILLER, C.J., INC. (A) 0.014	P	53	75	3	0	0	BAG	2.05	16.4	1.64	8	200	30
10	716 538	107	GREENVALLEY SCHOOL	I	37	72	0	0	0	BUR	1.33	4.0	.36	3	180	30
10	724 565	76	NEW MARKET ELEM.	I	56	78	0	0	0	BUR	.50	2.0	.18	4	180	4

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS	AREA EQUIP NO	YR INST	SULF[5] 0.1%	OIL GR	MBTU /HR	CONTROL EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK HT-FT
8	754 279	40	NAVAL ORDNANCE STA.-INDIAN HEAD	I	7 6	77 76	0	0	0		5.07 .88	30.4 3.5	.18 .18	6 4	72 104	32 45
8	826 288	1	ARUNDEL ASPHALT PRODUCTS (A)	P	1	69	10	0	0	BAG	1.62 ~~.20~~	~~1.6~~ 12.9	~~.18~~ 1.46	8	225	30
8	826 288	12	~~C & R CO.~~ Anthony Contractors, Inc. (A)	P	5	76 71	3	0	0	SCR	4.18 ~~3.43~~	~~27.4~~ 33.5	~~3.29~~ 4.02	8	240	1
8	845 263	44	CARRUTH & SON, INC.	P	1	76	0	0	0	DIS	1.49	11.9	1.82	8	306	0
18	873 221	21	ASHER CORP.	P	2	75	0	0	0	BAG	.91	7.3	.73	8	200	1
18	923 187	5	DEAN CONSTRUCTION CO. (A)	P	1	65	7	0	0	SCR	2.05	16.4	1.64	8	200	30
18	923 187	5	DEAN CONSTRUCTION CO. (A)	P	2	74	3	0	0	BAG	2.28	18.2	1.82	8	200	30

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	6 SULF 0.1%	OIL GR	MBTU /HR	CONTROL[2] EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK[3] HT-FT
7	1060 630	9	FIRESTONE PLASTICS	P	21	75	0	0	0	BAG	2.85	68.4	12.24	24	358	0
7	1060 630	9	FIRESTONE PLASTICS	P	22	75	0	0	0	BAG	2.85	68.4	12.24	24	358	50
7	1122 628	15	MITCHELL, STEWART E. INC. (A)	P	3	63	3	0	0	SCR	3.65 ~~.46~~	~~3.7~~ 29.2	~~.18~~ 1.46	8	100	30
7	1130 667	3	STOLTZFUS & SONS	P	15	72	0	0	0	OTH BAG	.21	1.7	.18	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	16	72	0	0	0	OTH BAG	5.18	41.4	4.56	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	17	72	0	0	0	BAG	.21	1.7	.18	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	18	72	0	0	0	BAG	2.90	23.2	2.55	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	19	72	0	0	0	BAG	2.07	16.6	1.82	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	24	72	0	0	0	BAG	.63	5.0	.55	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	25	72	0	0	0	BAG	2.90	23.2	2.55	8	220	0
9	1063 270	79	ZAPATA HAYNIE	P	7	77	0	0	0	OIS	8.30	66.4	.73	8	22	0
9	1068 270	15	COLDWATER SEAFOOD CORP.	P	39	73	0	0	0	SCR	.67	5.4	.54	8	200	30
9	1107 281	70	TUBMAN, GROVER JACK	I	3	73	0	0	0		.47	1.4	.18	3	260	11
9	1120 301	64	INTERSTATE AMIESITE CORP. (A)	P	4	71	3	0	0	SCR	4.79 ~~.60~~	~~4.8~~ 38.3	~~.48~~ 3.83	8	200	30
17	1073 490	6	BRAMBLE DAVID A. (A)	P	1	0	3	0	0	SCR	4.56 ~~.57~~	~~4.6~~ 36.5	~~.41~~ 3.28	8	180	30
19	1175 138	49	CELLUTRON PRODUCTS	P	4	77	0	0	0	BAG	2.29	55.0	8.57	24	312	0
20	1059 342	40	BRAMBLE DAVID A. (A)	P	1	0	3	0	0	SCR	0.76 ~~.09~~	~~.7~~ 6.1	~~.06~~ .55	8	180	50
20	1063 345	55	BLACK & DECKER MFG.	P	6	75	0	0	0	BAG	.19	1.5	.18	8	243	0
22	1195 199	26	H.D. METAL CO., INC.	P	17	72	0	0	0	BUR	4.38	35.0	4.38	8	250	30
22	1196 180	34	CROWN CORK & SEAL CO., INC.	P	35	72	0	0	0	BUR	.10	2.4	.37	24	312	50
22	1196 180	89	NICHOLS, S.E. DEPT. STORE	I	14	73	0	0	0	BUR	.58	4.6	.72	8	312	27
22	1203 197	86	HICKORY RIDGE FOODS	P	34	72	0	0	0	SPR	.22	1.8	.18	8	200	1
22	1203 197	94	HOFFMAN-LAROCHE, INC.	P	36	74	0	0	0	BAG	.88	7.0	1.10	8	312	1
22	1208 228	8	INTERSTATE AMIESITE CORP. (A)	P	40	75	3	0	0	SCR	4.11	32.9	3.29	8	200	30
23	1212 66	51	ELLER, LANCE J. INC.	P	6	72	3	0	0	SCR	7.07	56.6	5.66	8	200	30
23	1315 189	10	EASTERN ANIMAL FOODS	P	47	77	0	0	0	SCR	.05	1.2	.18	24	300	0

NOTE:

1. P: Process, I: Incinerator
2. BAG: Baghouse, BUR: Afterburner, CYC: Cyclone, SCR: Scrubber, SPR: Sprayer, MCY: Multicyclone, OIS: Other Inertia Scrubber, OTH: Other
3. 1:0-30', 0:stack height not applicable--rooftop vent, etc.

TABLE III

PREDICTIONS OF MAXIMUM CONCENTRATION INCREMENTS
FOR THOSE PREMISES WHICH EXCEED PSD INCREMENTS
OR NATIONAL AMBIENT AIR QUALITY STANDARDS
(Concentration increment shown are due to the impact
of all sources at a particular premise)

Source	Pollutant	Maximum Concentration Increments (ug/m^3) 3-hour	24-hour	Annual	Distance (km)	Stability	Windspeed (m/s)	Remarks
Celanese	SO_2		243	61	1.1 (WSW)	E	2.5	Terrain Impingement
Kelly-Springfield	SO_2	363	161	13	1.6 (south)	F	1.0	Terrain Impingement
	TSP	----	71	2[a]	.4	F	2.5	Downwash
PPG	SO_2	419	186	4	2.4 (ENE)	F	1.0	Terrain Impingement
Westvaco	TSP	----	299	14[a]	.5 (NW)	F	1.0	Terrain Impingement
Potomac Edison*	SO_2	1477	696		.7	A	3.0	
Byron & Son*	SO_2	331	147		.4	B	1.0	Downwash
Md. Corr. Inst.*	SO_2	426	190		.5	A	3.0	
Fairchild*	SO_2	2581	1147		.4	F	2.5	Downwash
Mack*	SO_2	228	102		.4	B	1.0	Downwash
Eastalco	TSP	----	113	7[a]	.8	E	2.5	Downwash
Stoltzfus	TSP	----	67		.4	C	2.0	

* Annual increment not given, since these were modeled together.

a Arithmetic average

NOTE: Federal PSD increments for Class II areas may be found in Table I.

TABLE IV

Description of SO_2 Sources Predicted to Exceed PSD Increments or NAAQS

Premise Name	Type of Fuel-Burning Equipment	MM BTU Size	Maryland Registration No.	PSD Violation	Standard Violation	Remarks
Celanese	4 gas/oil boilers	276	01-71-5-00053	24-hr., Ann	24-hr	NUS Report 1978 (1 coal-Unit 5, 1 oil)
		276	01-71-5-00054			
		276	01-71-5-00055			
		276	01-77-5-00056			
Kelly-Springfield	2 coal boilers	180	01-49-3-00108	3, 24-hr, Ann	3, 24-hr	
		180	01-49-3-00109			
	1 oil boiler	135	01-69-4-00002			
PPG Industries	3 coal boilers	64	01-56-3-00010	24-hr	~~---~~ 24-hr	
		64	01-56-3-00011			
		64	01-56-3-00012 standby			
Potomac Edison	2 coal boilers	382	21-00-3-00005	3,24-hr	3,24-hr	
		710	21-71-3-00006			
W. D. Byron & Son	2 oil boilers	25	21-71-4-00103	24-hr	---	@400m, B-stability, 1 m/sec, downwash
		25	21-71-4-00104			
Md. Correc. Inst.	3 coal boilers	36	21-65-3-00051	24-hr	---	
		86	21-65-3-00052			
		100	21-65-3-00053			
	1 oil boiler	3	21-65-4-00141			
Fairchild Republic	4 oil boilers	19	21-44-4-00095	3,24-hr	3,24-hr	@400m, F-stability 2.5 m/sec, downwash
		19	21-44-4-00096			
		40	21-44-4-00097			
		40	21-44-4-00098			
Mack Trucks	3 oil boilers	140	21-00-4-00006	24-hr	---	@400m, B-stability 1 m/sec, downwash
		140	21-00-4-00007			
		140	21-00-4-00008			

TABLE V

Description of TSP Sources Predicted to Exceed PSD Increments or NAAQS

Premise Name	Type of Process	Control Equipment	Maryland Registration No.	PSD Violation	Standard Violation	Remarks
				Date of Appl, Starting Date, Date of Completion		
Westvaco	2 smelt dissolving tanks on No. 3 recovery boiler	Mesh pad scrubber	01-72-7-00032	24-hour	24-hour	
		Mesh pad scrubber	01-72-7-00033	?	Annual	
Kelly-Springfield	Rubber buffing (tire balancing)	Type W rotoclone	01-73-6-00060	24-hour 3-5-73	24-hour 3-19-73	@400m, F-stability 2.5 m/sec, downwash
	Hand buffer station for tire repair buffing line	Dry centrifugal rotoclone	01-77-6-00070	3-22-77, 3-28-77, 5-6-77		@800m, no PSD violation
	3 Goodyear force-grind tire tread grind machines	Cyclone	01-76-6-00069	5-26-76, 4-19-76, 5-28-76		
		Cyclone	01-77-6-00071	7-21-77, 7-29-77, 8-19-77		
		Cyclone	01-77-6-00072	8-1-77, 6-17-77, 7-18-77		
Eastalco	"B" potline (Electrolytic-cells)	Baghouse	10-75-7-00053	9-17-73, 24-hour	9-19-73, 12-1-75, 24-hour,	Date operation 8-1-75 Downwash
		Baghouse	10-75-7-00054		Annual	
	"B" Carbon Anode Furnace	Scrubber	10-75-7-00064	10-17-73,	11-15-73, 5-1-75	
Stoltzfus & Sons	4848 Universal Jaw Crusher	Baghouse & Sprays	07-74-9-00015	Appl date 24-hour 8-1-74,	Date operation 24-hour 9-1-72	@400m, C-stability 2 m/sec
	36FC Gyrasphere Crusher	Baghouse & Sprays	07-74-9-00016	8-1-74	9-1-72	
	1051AC Hydracone Crusher	Baghouse	07-74-9-00018	8-1-74	9-1-72	
	48FC Gyrasphere Crusher	Baghouse	07-74-9-00019	8-1-74	9-1-72	
	4895 Telsmith Gyra Crusher	Baghouse	07-74-9-00024	8-10-74	9-1-72	
	48FC Telsmith Gyra Crusher	Baghouse	07-74-9-00025	8-10-74	9-1-72	

KGY April 20, 1979

Title 10
Department of Health and Mental Hygiene
Environmental Health Administration

The Department of Health and Mental Hygiene is proposing adoption of amendments to Regulation .03 Air Pollution Episode System and Regulation .04 Ambient Air Quality Standards under COMAR 10.18.01 Control of Air Pollution in the State; Regulations .02 Control and Prohibition of Visible Emissions, .03 Control and Prohibition of Particulate Matter Emissions, .04 Control and Prohibition of Gas and Vapor Emissions, .06 Control and Prohibition of Certain New Fuel Burning Equipment under COMAR 10.18.02 Air Pollution in Area I, COMAR 10.18.03 Air Pollution in Area II, COMAR 10.18.06 Air Pollution in Area V and COMAR 10.18.07 Air Pollution in Area VI; and Regulation .04 Control and Prohibition of Gas and Vapor Emissions under COMAR 10.18.04 Air Pollution in Area III and COMAR 10.18.05 Air Pollution in Area IV.

The purpose of these amendments is to comply with the legislative mandate now codified at §693(b)(3) to (8), Article 43, Annotated Code of Maryland which, in general, requires the DHMH to establish air quality standards identical to the national ambient air quality standards and emission standards no more restrictive than necessary to attain and maintain the ambient air quality standards. To this end, the proposed amendments will change the State's air quality standards, for the pollutants for which there are federal standards, to be consistent with those standards. They also add a new ambient air quality standard for lead and change the air quality standard and episode criteria to be consistent with the new federal ozone standard. In addition, the proposed amendments also contain substantial change to the State's emission standards.

On a statewide basis, the proposed amendments will relax the emission limitation for nitrogen oxides from solid fuel-fired new fuel burning equipment. In the urban areas, the 0.5 percent sulfur limitation on residual fuel oil, which was to be imposed after July 1, 1980, has been raised to the current 1% limit. The remaining changes are restricted to the rural areas of the State. The major revisions to the rural area regulations are as follows: a relaxation from the existing no visible emission limitation from facilities constructed after January 17, 1972 to 20 percent opacity; removal of the requirement for dust collection devices on residual oil-fired equipment constructed after January 17, 1972; relaxation of the emission limitations for particulate matter from installations constructed after January 17, 1972, including fuel burning equipment, incinerators and asphalt concrete plants, and lowering of the prohibition on construction of new solid fuel burning equipment from 50 to 13 million Btu per hour rated capacity.

There is an additional provision which is being proposed which would require certain sources in Area I to meet a different emission standard for sulfur content of fuels than is required for other sources in the same area. This particular provision must be read in the context of applicable federal regulations in order to be understood. While the existing Maryland regulation imposes a 2 percent sulfur content limitation on residual fuel oil and a 3.5 pound per million BTU limit on sulfur oxides from the combustion of solid fuel, there is a federally enforceable requirement in effect which limits sulfur content of fuel to 1 percent in Area I. This more restrictive federal requirement will remain until the EPA approves this revision to its air quality implementation plan. To date, the EPA has refused to approve the State's relaxation to a 2 percent sulfur emission standard in Area I because of the potential impact on the attainment and maintenance of national ambient air quality standards. The provision in question has been proposed as a means of removing the impediment to federal approval of the State's relaxed standard. The accompanying screening demonstration will identify those sources which would case or exacerbate a violation of federal ambient air quality standards or PSD increments if they were allowed to burn the higher sulfur fuel. Those sources will be required to continue to burn the low sulfur fuels, while all other sources could take advantage of the relaxed sulfur content standard. Use of the Department's screening demonstration techniques indicate that the following fuel burning sources will be restricted to one percent sulfur fuels:

Celanese
Kelly-Springfield Tire
PPG Industries
Potomac Edison
W. D. Byron and Son
Maryland Correctional Institute
Fairchild Republic
Mack Trucks

A similar provision has been included in the proposed regulation controlling particulate matter emissions from other installations (COMAR 10.18.02.03F(3), 10.18.03.03F(3), 10.18.06.03F(3) and 10.18.07.03F(3)). The Department's screening demonstration indicated that an overall relaxation of particulate matter control requirements would in general not exceed National Ambient Air Quality Standards. However, the demonstration revealed that localized problems could be expected in the vicinity of the following sources:

Westvaco (smelt dissolving tanks)
Kelly-Springfield (buffers, tire tread grinders)
Eastalco Aluminum (potline electro-cells, carbon anode furnace)
Stoltzfus and Sons (stone crushing)

Therefore, these sources will be restricted to the existing emission standard of 0.03 gr/SCFD.

The Department anticipates that some changes in style or format, particularly for the sulfur content of fuel regulation and the particulate matter regulation, may be necessary in order to insure enforceability and eventual federal approval of these amendments.

Screening Demonstration Description

To evaluate the impact of the proposed amendments on the Prevention of Significant Deterioration (PSD) increments and the National Ambient Air Quality Standards (NAAQS) for Total Suspended Particulate (TSP) and Sulfur Dioxide (SO_2),[1] concentration estimates were calculated for the amendment-affected sources[2] using emission rates based on the proposed emissions limitations. Annual average emission rates reported in the Maryland registration files yem were used to predict annual concentrations. For predicting short-term concentrations, hourly emission rates were calculated from annual emissions by dividing annual rates by the sources annual operating hours. Because some sources operated less than 24-hours/day, their hourly emission rates had to be adjusted before 24 hour predictions were made. The adjustment was made, for sources operating less than one shift per day, by dividing the sources' operating hours by 9, where a 9 hour wind persistence is the standard figure used by U.S. EPA. No such adjustment was necessary for the 3 hour averaging time. For predicting PSD increment concentrations, an additional factor was applied to emission rates to represent the emission increases allowed by the proposed amendments. This factor was one for SO_2 sources, since the only other residual oil available in amendment-affected areas contains 100% more sulfur than the currently used oil, and the proposed coal sulfur limit is double the current content. TSP emission rate increases due to the TSP emission standard relaxation are given in the following table.

Type Process	Current Limit (gr/SCFD)	Proposed Limit (gr/SCFD)	Increased Emission Factor
Process with control equipment (built since 1/17/72)	.03	.05	.667
Asphalt Plant (built before 1974)	.03	.05	.667
Asphalt Plant (built since 1974)	.03	.04	.333
Non-pathological incinerator (built since 1/17/72)	.03	.1	2.33

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[1] See Appendix Table I for applicable PSD increments and ambient air quality standards.
[2] For a list of all amendment-affected sources, see Appendix Table II.

Isolated and Major Source Calculations

Because of the different modeling requirements, the affected sources were separated into three categories: major sources, those sources close enough to interact, and those which could be considered isolated. An impact analysis of the isolated sources affect on the short-term PSD increments and NAAQS was performed according to the Guidelines for Air Quality Maintenance and Planning, Vol. 10, Sec. 4.3, 1977. Because a complete set of stack parameters was not available for each source, the following effective stack height assumptions were made when necessary in accordance with the above guidelines:

Plume Condition	Effective Stack Height
Looping	Twice the physical height
Coning	Twice the physical height
Limited Mixing	Physical Height
Fanning	Physical Height

The effective stack height for horizontal stacks was taken to be the physical stack height for all stability classes. For most sources, registration information reported ranges of stack heights (e.g. 31-50'). In those cases, the lowest height was used, and for the 0-30' range, a 15' stack height was assumed. Because of the probable proximity of higher buildings, downwash was assumed to occur at all stacks shorter than 20'. Field observations were made by Air Quality Programs personnel to determine the downwash potential of the following major sources: R. P. Smith (Potomac Edison), Celanese, Kelly-Springfield, PPG Industries, Maryland Correctional Institute, Mack Truck, Fairchild Industries, W. D. Byron, Roper Eastern, and Gilbert Industries.

Turner & Snyder

Briggs' Diffusion Estimation for Small Emissions, 1973, Sec. 2.1-3.4 was used to predict ground level concentrations for sources with downwash potential.

To evaluate the impact of premises having more than one source, the guidelines' suggestion for merging stack parameters was utilized when possible. Since merging was usually not possible, ~~a modified CRSTER model~~ Turner's WADE with limited mixing was used to evaluate most of these premises. Since previous Valley model results were available for Westvaco[1], Kelly-Springfield, Celanese and PPG Industries,[2] these results were adopted and modified for

[1] SO_2 results for Westvaco were obtained from a 1976 ERT model run.

[2] Results of previous modeling for Cumberland were given in the Maryland Air Quality Technical Memorandum 77-03, 1977.

use in this analysis.

One hour concentrations predicted by the Guidelines and the Turner's WADE ~~modified CRSTER model~~ were converted to 3-hour and 24-hour concentrations by using the factors suggested in the Guidelines Section 4.2 -- .9 for 3-hour, .4 for 24-hour. Normally, the largest of the max concentrations for each stability class was chosen for comparison to PSD increments and NAAQS. However, max concentrations occurring during E and F stabilities were ignored for sources operated only during the day. Since premise property boundaries were not readily available, concentration estimates occurring 400 meters downwind from a source were chosen for comparison to standards for sources with downwash potential. Table III shows the incremental increases which would result if the relaxations were allowed at those premises. Tables IV and V of the Appendix show those major sources and isolated sources which exceeded Federal standards or PSD increments.

Interacting Sources

Because of the density of proposed amendment-affected sources in Cumberland, Frederick and Hagerstown, models capable of evaluating multi-source interaction in urban areas were employed to predict impact on both annual and short-term PSD increments and NAAQS's. Major sources located nearby these urban areas were also made part of the analysis. Those sources that exceeded standards or increments by previous demonstrations were held to emissions that reflected existing limitations (Table III sources).

The State's Multiple Source Dispersion Model[1] was used to predict concentrations in Frederick and Hagerstown. Meteorological data for these cities were taken from Martinsburg, West Virginia airport. The State's version of EPA's model, C9M3D, was used for the Cumberland analysis. Meteorological data for Cumberland was a combination of wind data from Cumberland City Hall and ceiling height and cloud cover from Pittsburgh.

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1 See description in the 1979 State Implementation Plan Amendments for the Baltimore Intrastate Air Quality Control Region, January, 1979.

Max Predicted in Cumberland 24-hr 2.3, ann 0.3

explanation → Prediction of the impact on the NAAQS in Cumberland is given in the following table:

TSP

where

City Hall Average Time	Observed Concentrations 1978 (ug/m^3)	Predicted Max. Concentrations (ug/m^3)	Sum (ug/m^3)
24-hour 2nd highest	144	2.3	146.3
Annual	68	0.3	68.3
Workshop for Blind			
24-hour 2nd highest.	127	2.3	129.3
Annual	64	0.3	64.3

Examination of the tables shows no violation of standards or increments. The sources involved are Celanese, Cumberland Contracting and Liller Brothers Asphalt, those for particulate relaxations. There were no SO_2 sources affected.

The following Frederick TSP sources will be relaxed by the proposed amendment: Campbell-Grove, Etzler Co., R. F. Kline, C. J. Miller, North Frederick Elementary School, Fort Detrick, and Walkersville High School. No SO_2 sources were assumed to be close enough to interact. Model results predict a max TSP concentration increase of 1 ug/m^3 for the annual average and 4 ug/m^3 for the 24-hour average. These values are considered insignificant with respect to PSD as indicated in Federal Register, Vol. 43, No. 118.

The following Hagerstown SO_2 and TSP sources will be relaxed by the proposed amendments:

TSP	SO_2
Marquette Cement	Hagerstown Municipal Light Plant
H. B. Mellott	Columbo, Inc.
Blaine Window Hardware	Roper Eastern
Conservit, Inc.	Victor Hosery Corp.
Bester-Long, Inc.	Supreme Concrete Block
O. O. Craig	Jamison Door
	Hagerstown P. O.
	Beachley Furniture
	Manbeck Bread
	Gray Concrete
	Gilbert Industries
	Maryland Machine and Foundry

Predicted maximum concentration increases for Hagerstown are:

Average Time	TSP Concentrations (ug/m^3)	SO_2 Concentrations (ug/m^3)
3-hour	--	28
24-hour	3	17
Annual	1	4

TSP concentrations are insignificant as described above. SO_2 concentrations are significant but below allowed PSD increments.

Impact on the NAAQS's in Hagerstown was evaluated by adding the short term and annual predictions nearest the monitoring sites to the observed highest short term concentration and the observed annual concentration, respectively.

In summary, the smaller interacting sources not screened out by the major and isolated source modeling exercises did not show any interference with PSD increments or National Ambient Air Quality Standards. These sources, therefore, could take full advantage of the relaxation if approved by EPA.

Further Refinements

As proposed at this time, the regulation amendments are based on a conservative analysis of the impacts on ambient air. In many cases several of the input parameters to the screening model may have been overly conservative. Such assumptions were necessary due to the large number of sources affected by the amendment and the limited resources available for the analysis.

It is intended that more refined analysis be undertaken in order that more sources can be benefitted by these amendments. Such refined demonstrations, however, will be carried out by the affected source. In the case of Westvaco, for example, a more refined analysis has been completed by consultants for the company and has demonstrated compliance with air quality standards at the higher emission rates allowed by the amendments. Such higher emissfon rates have been allowed by the Department and, therefore, supercede the effect of this screening demonstration. Pending approval by the EPA, the higher emission rate will be the applicable rate under Federal law as well as State law.

For more information on the more refined level of analysis, contact Mr. Bonta at 383-3245.

APPENDIX

TABLE I

PSD Increments
and
National Air Quality Standards

	Average Time	PSD Increment (ug/m^3)	NAAQS (ug/m^3)	Level of Significance (ug/m^3)
SO_2	3-hour	512	1300*	25
	24-hour	91	365	5
	Annual	20	80	1
TSP	24-hour	37	150*	5
	Annual	19	60#	1

* Secondary standard, all others are primary standards

\# Geometric mean, guideline

Increments are for Class II areas

Annual limits are not to be exceeded. Other standards and increments may be exceeded once annually.

Subtitle 18 AIR QUALITY PROGRAMS

Authority: Article 43, §697,
Annotated Code of Maryland

Notice of Proposed Action

The Department of Health and Mental Hygiene is proposing adoption of amendments to Regulation .03 **Air Pollution Episode System** and Regulation .04 **Ambient Air Quality Standards, under COMAR 10.18.01 Control of Air Pollution in the State;** Regulations **.02 Control and Prohibition of Visible Emissions, .03 Control and Prohibition of Particulate Matter Emissions, .04 Control and Prohibition of Gas and Vapor Emissions, .06 Control and Prohibition of Certain New Fuel Burning Equipment,** under **COMAR 10.18.02 Air Pollution in Area I, COMAR 10.18.03 Air Pollution in Area II, COMAR 10.18.06 Air Pollution in Area V,** and **COMAR 10.18.07 Air Pollution in Area VI;** and Regulation **.04 Control and Prohibition of Gas and Vapor Emissions,** under **COMAR 10.18.04 Air Pollution in Area III,** and **COMAR 10.18.05 Air Pollution in Area IV.**

The purpose of these amendments is to comply with the legislative mandate now codified at §693(b)(3) to (8), Article 43, Annotated Code of Maryland, which, in general, requires the DHMH to establish air quality standards identical to the national ambient air quality standards and emission standards no more restrictive than necessary to attain and maintain the ambient air quality standards.

The amendments will constitute a revision to the State's Air Quality Implementation Plan and must be submitted to the Environmental Protection Agency for approval pursuant to 40 CFR §51.6. The proposed amendments will change the State's air quality standards, for the pollutants for which there are federal standards, to be consistent with those standards. They also add a new ambient air quality standard for lead and change the air quality episode criteria to be consistent with the new federal ozone standard.

The proposed amendments also contain substantial changes to the State's emission standards. On a statewide basis, the proposed amendments will relax the emission limitation for nitrogen oxides from solid fuel-fired new fuel burning equipment. In the urban areas, the .5 percent sulfur limitation on residual fuel oil, which was to be imposed after July 1, 1980, has been removed. The remaining changes are restricted to the rural areas of the State and represent a relaxation from the existing emission standards. The major revisions to the rural area regulations are as follows: a 20-percent opacity limitation for visible emissions from facilities constructed after January 17, 1972; removal of the requirement for dust collection devices on residual oil-fired equipment constructed after January 17, 1972; relaxation of the emission limitations for particulate matter from installations constructed after January 17, 1972, including fuel burning equipment, incinerators and asphalt concrete plants; and lowering of the prohibition on construction of new solid fuel burning equipment from 50 to 13 million Btu per hour.

There is an additional provision which has been proposed which would require certain sources in Area I to meet a different emission standard for sulfur content of fuels than is required for other sources in the same area. This particular provision must be read in the context of applicable federal regulations in order to be understood. While the existing Maryland regulation imposes a 2 percent sulfur content limitation on residual fuel oil and a 3.5 pound per million Btu limit on sulfur oxides from the combustion of solid fuel, there is a federally enforceable requirement in effect which limits sulfur content of fuel to 1 percent in Area I. This more restrictive federal requirement will remain until the EPA approves the State's regulation as a revision to its air quality implementation plan. To date, the EPA has refused to approve the State's relaxation to a 2 percent sulfur emission standard in Area I because of the potential impact on the attainment and maintenance of national ambient air quality standards. The provision in question has been proposed as a means of removing the impediment to federal approval of the State's relaxed standard. The accompanying demonstration will identify those sources which would cause or exacerbate a violation of federal ambient air quality standards or PSD increments if they were allowed to burn the higher sulfur fuel. Those sources will be required to continue to burn the low sulfur fuels, while all other sources could take advantage of the higher sulfur content standard. Use of the Department's screening techniques indicate that the following fuel burning sources will be restricted to one percent sulfur fuels:

Celanese Corporation
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Maryland Correctional Institute
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Mack Trucks

A similar provision has been included in the regulation controlling particulate matter emissions from other installations **(COMAR 10.18.02.03F**(3), **10.18.03.03F**(3), **10.18.06.03F**(3), and **10.18.07.03F**(3)). The Department's screening procedure indicated that an overall relaxation of particulate matter control requirements would not adversely affect air quality in general. However, the procedure revealed that localized problems could be expected in the vicinity of the following sources:

Westvaco (smelt dissolving tanks)
Kelly-Springfield (buffers, tire tread grinders)
Eastalco Aluminum (potline electro-cells, carbon anode furnace)
Stoltzfus and Sons (stone crushing)

Therefore, these sources will be restricted to the existing emission standard of .03 gr/SCFD.

The Department anticipates that some changes in style or format, particularly for the sulfur content of fuel regulation and the particulate matter regulation, may be necessary in order to insure enforceability and eventual federal approval of these amendments.

Estimate of Economic Impact

I. **Summary.** These proposed amendments will relax certain emission limitations on facilities located in certain parts of the State and will revise the State's ambient air quality standards to be consistent with the federal standards.

II. Types of Economic Impacts.	Revenue (+) Expense (−)	Magnitude
A. On issuing agency:	None	
B. On other State or local agencies affected:	None	

	Benefit (+) Cost (−)	Magnitude
C. On regulated industries or trade groups:		
1. Ability to use higher sulfur fuels.	(+)	Cannot be determined
2. Ability to decrease power usage.	(+)	Cannot be determined
3. No need for dust collector devices on residual oil fired burners.	(+)	Cannot be determined
4. Ability to construct solid fuel burning equipment between 13 & 50 MM Btu.	(+)	Cannot be determined
5. Possible inducement to expansion.	(+)	Cannot be determined
D. On other industries or trade groups affected:		
1. Vendors selling solid fuel burning units less than 50 MM Btu heat input.	(+)	Cannot be determined
2. Vendors of dust collection equipment.	(−)	Cannot be determined
3. Maryland coal producers.	(+)	Cannot be determined
E. Direct and indirect effects on public:		
1. Increase in ambient levels of suspended particulate and sulfur dioxide.	(−)	Cannot be determined
2. Lower costs to the consumer for certain products and services.	(+)	Cannot be determined

III. Assumptions. (Identified by Impact Letter and Number from Section II):

C.1. Assumes fuels with higher sulfur contents cost less than low sulfur fuels. Impossible to assess magnitude because of uncertainty as to which facilities will change fuels, what the sulfur content will be, and what the price differential would be.

2. Assumes that power usage by certain types of control equipment can be reduced.

3. Assumes that facilities can comply with proposed requirements without dust collectors.

4. Assumes that construction of small solid fuel fired fuel burning equipment will be cheaper to construct and/or operate than comparable oil fired units.

D.1. Assumes that vendors of solid fuel burning units less than 50 MM Btu heat input (but greater than 13 MM Btu) will now sell their units in Maryland.

2. Assumes that vendors of dust collection equipment will have a reduced market in Maryland.

3. Assumes that coal use will increase because of increase in the number of small units and ability to use higher sulfur fuel.

E.1. Assumes that any increase in ambient levels of air pollution is associated with increased costs. However, the expected levels will not exceed the Federal health and welfare standards and the increments established to prevent significant deterioration of air quality.

2. Assumes that those facilities which take advantage of relaxed emission limitations will pass on any savings which are realized to the consumer.

Opportunity for Public Comment

The Environmental Health Administration will hold hearings concerning adoption of these amendments June 4, 1979, at 10:30 a.m. in the 2nd Floor Auditorium of the Washington County Health Department, 1302 Pennsylvania Avenue, Hagerstown, Maryland 21740; on June 5, 1979, at 10 a.m. in the Laboratory Auditorium of the Herbert R. O'Conor State Office Building, 201 West Preston Street, Baltimore, Maryland 21201; and on June 8, 1979, at 1 p.m. in Room 106 of the Government Office Building, Route 5 and North Division Street, Salisbury, Maryland 21801.

Written comments may be sent to Raymond A. Huber, Regulations Coordinator, O'Conor Building, Room 314-A, 201 West Preston Street, Baltimore, Maryland 21201. These comments must be received no later than June 8, 1979.

10.18.01 Control of Air Pollution in the State of Maryland

.03 Air Pollution Episode System.

A. (text unchanged)

B. Air Pollution Episode Criteria.

(1) (text unchanged)

(2) Episode Criteria.

(a) (text unchanged)

(b) Alert Stage. An alert shall be declared by the Secretary or his designee when any one or more of the following pollutant levels is attained concurrent with:

(i) A judgment by the Department that the pollutant level is representative of air quality in a significant portion of the region. The Department shall consult the air pollution control agencies of the affected jurisdictions to help evaluate local situations.

(ii) Meteorological conditions are such that pollutant dispersion is expected to be inhibited for 12 or more hours.

(iii) Pollutant levels.

POLLUTANT	LEVEL
(aa) Sulfur dioxide	.3 ppm 24 hour average
(bb) Particulate matter	3.0 COH's 24 hour average
(cc) Sulfur dioxide and particulate matter	Combined product of 24 hour SO_2 and COH's equal to .2
(dd) Carbon monoxide	15 ppm 8 hour average
(ee) **[**Photochemical Oxidant**]** *Ozone*	**[**0.1**]** *.2* ppm 1 hour average
(ff) Nitrogen dioxide	.6 ppm 1 hour average or .15 ppm 24 hour average

(c) Warning Stage. A warning shall be declared by the Secretary or his designee when any one or more of the following pollutant levels is attained concurrent with:

(i)—(ii) (text unchanged)

(iii) Pollutant levels.

POLLUTANT	LEVEL
(aa) Sulfur dioxide	.6 ppm 24 hour average
(bb) Particulate matter	5.0 CHO's 24 hour average
(cc) Sulfur dioxide and particulate matter	Combined product of 24 hour SO_2 and COH's equal to .8
(dd) Carbon monoxide	30 ppm 8 hour average
(ee) [Photochemical Oxidant] *Ozone*	.4 ppm 1 hour average
(ff) Nitrogen dioxide	1.2 ppm 1 hour average or .3 24 hour average

(d) Emergency Stage. An emergency shall be declared by the Governor when any one or more of the following pollutant levels is attained concurrent with:

(i)—(ii) (text unchanged)

(iii) Pollutant levels.

POLLUTANT	LEVEL
(aa) Sulfur dioxide	.8 ppm 24 hour average
(bb) Particulate matter	7.0 COH's 24 hour average
(cc) Sulfur dioxide and particulate matter	Combined product of 24 hour SO_2 and COH's equal to 1.2
(dd) Carbon monoxide	40 ppm 8 hour average
(ee) [Photochemical oxidant] *Ozone*	.5 ppm 1 hour average
(ff) Nitrogen dioxide	1.6 ppm 1 hour average or .4 ppm 24 hour average

(e) (text unchanged)

(3)—(4) (text unchanged)

C.—D. (text unchanged)

.04 Ambient Air Quality Standards.

[A. Definitions. For purposes of the ambient air quality standards in this section only, the following definitions shall apply.

(1) Sulfur oxides means sulfur dioxide, sulfur trioxide, their acids, and the salts of their acids. For purposes of these ambient air quality standards, measurements of sulfur dioxide shall be taken by the methods specified herein to indicate the concentration of sulfur oxides.

(2) "Particulate Matter" means the substances collected from or settling out of, the atmosphere by use of the measurement procedures prescribed in these regulations for suspended particulate matter and dustfall, respectively.

(3) "Non-Methane Hydrocarbons" means a class of organic compounds, excluding methane, whose molecules consist primarily of atoms of hydrogen and carbon and which exist in the ambient air in the gaseous state. Specifically excluded are hydrocarbons and other organic compounds associated only with suspended particles in the atmosphere. For purposes of these air quality standards, non-methane hydrocarbons means the difference between the reported total hydrocarbons and methane values measured by the methods specified herein.

(4) "Photochemical Oxidants" means complex photochemical reactions involving non-methane hydrocarbons, oxides of nitrogen and sunlight that when they occur in the ambient air, result in the formation of photochemical oxidants. For purposes of these ambient air quality standards, the measurement of ozone, the predominant constituent of these oxidants, shall be taken by the method specified in these regulations to indicate the concentration of photochemical oxidants.]

[B. Precepts.

(1) It is known that concentrations of air pollutants above certain levels are harmful to the health of man. However, the threshold levels at which adverse effects of man's health begin are not known with precision. It must be presumed that adverse effects over a long time period take place at concentrations lower than those now known to produce adverse effects over short time periods. Therefore, in establishing air quality standards, it is prudent to provide for margins of safety in reaching conclusions based on available data that relate health effects to pollutant levels.

(2) An ambient air quality standard which would result in avoidable degradation of air quality is in conflict with applicable state law.

(3) The ambient air quality standards set forth in these regulations represent goals expressed in terms of limits on the duration and concentration of pollutants in the atmosphere which are not to be contravened. The ambient air quality standards shall be achieved through application, under provisions of laws or regulations or otherwise, of means for reducing pollutant concentrations including removal of air pollutants from exhaust gas streams, fuel and process and material changes, equipment changes, and land use management.]

[C. Primary Ambient Air Quality Standards for All Substances Which May Cause Air Pollution and Control Measures to be Returned.

(1) The primary ambient air quality standards for all substances which may cause air pollution shall be those lowest concentrations attainable by application of all reasonably available means for reducing pollutant concentrations in the ambient air. In situations where the lower concentrations of any substance in the "more adverse range" as set forth in these regulations are not exceeded, or—when there is no standard at the "more adverse range"—where the "serious level" is not exceeded, all necessary means shall be required for minimizing increases in concentrations of those substances in the ambient air, so that those concentrations shall not be exceeded in the future.

(2) No statement, numerical standards, or time limit, contained elsewhere in ambient air quality standards shall be interpreted as mitigating the necessity for the application of all reasonable means for reducing pollutant concentrations in the ambient air.]

[D. Secondary Ambient Air Quality Standards - More Adverse Range. When ambient air concentrations of any pollutant listed in Table 1, are in the more adverse range, as set forth in Table 1 the application of all necessary means for reducing those concentrations shall be required and the time schedule for their implementation shall be based on the premise that the pollutant concentrations are progressively to be reduced to the lower level or less as set forth in Table 1, within the shortest reasonable time. Such reasonable time should not exceed 7 years, shorter time may be specified under provisions of the Federal Clean Air Act.]

[E. Secondary Ambient Air Quality Standards—Serious Level. When ambient air concentrations of any pollutant listed in Table 1 exceed the serious level, as set forth in Table 1, all necessary means shall be applied to reduce those concentrations. The means required and the time schedule for their implementation shall be based on the premise that the pollutant concentrations are progressively to be reduced to levels lower than the serious levels concentrations set forth in Table 1 in the shortest possible time. If ambient air concentrations exceed the serious levels specified in Table 1 as of the year 1971, such concentrations should be reduced to less than the serious levels by not later than the end of calendar year 1974. If, in the future, ambient air concentrations first exceed the serious level, reduction below the serious level shall occur within 3 years from the year in which the serious level is first exceeded, or in a shorter time, if required under provisions of Federal law or regulations. In determining the means for reducing pollutant concentrations, matters of economics and private interests and other factors shall be subordinate considerations to the necessity of achieving the standards for protection of the public health. Additionally, if standards have been adopted for the more adverse range, measures for reducing concentrations of the pollutant further below the serious level shall be instituted in accordance with the provisions of subsection D, above.]

[F. Method of Measurement. Measurement of ambient air quality to compare to the standards including reporting of measurements for each pollutant listed in Table 1 shall be by the method specified in 40 CFR, 50; 36 FR 22384, Nov. 25, 1971, and the methods manual entitled "Standard Methods for the Determination of Air Pollution Measurements made at Ambient Air Sampling Stations in the State of Marylend", as developed by the Bureau of Air Quality Control of the Department. Other methods may be used if they have been demonstrated to be equally or more specific, accurate, sensitive and reproducible and if first approved by the Department. Other less specific methods of measurement may be used provided a relationship is developed between results obtained by this method and the method specified; provided this relationship is approved by the Department. Results shall be expressed as micrograms or milligrams of the pollutant per cubic meter of air, at 25 degrees Celsius and 760 millimeters of mercury pressure except as specifically noted in Table 1. Such values may be converted to parts per million by volume (ppm) by utilizing the appropriate conversion factor listed in Table 1.]

[G. Number and Duration of Measurement. Pollutant measurements determined by the methods specified may be determined either by operation of cumulative type samplers or by continuous monitoring instruments. Specific definitions of measurement period values and statistical methods to be used to obtain levels for comparison to the standards are as indicated in the following appropriate subsection.

(1) Dustfall. The annual arithmetic average shall be based on at least nine of 12 possible monthly levels that can be determined during a year; there shall be at least two valid monthly levels reported in each calendar quarter.

(2) All Other Cumulative Type Pollutant Measurement.

(a) Daily average levels shall be on a midnight to midnight E.S.T. period with a minimum sampling frequency of every sixth day for each specific date starting January 4, 1972. Samples may be taken on a more frequent schedule provided that samples are also taken on the specified dates.

(b) The annual arithmetic mean shall be based on at least 75 percent of the possible valid daily (24-hour) values obtainable at a location under previously specified sampling schedule, distributed through the year to reflect adequately the mean of 365 possible observations. Other statistical procedures may be used to evaluate the data to determine probable values of missing data, if the methods have been approved previously by the Department.

(3) Continuous Monitoring Instruments. The primary reportable pollutant value for all measurements determined by a continuous monitoring instrument shall be the hourly value; other statistical averages for the averaging times specified in the following subparts may be obtained by appropriately processing the hourly value.

(a) A valid hourly average level shall be based upon at least 58 percent of the possible data obtainable from the system during the hour.

(b) A valid 3-hour value shall be the arithmetic average of at least two of the possible three hourly values during a 3-hour period.

(c) A valid 8-hour value shall be the arithmetic average of at least six of the possible eight hourly values during a day (12 midnight to 12 midnight E.S.T.).

(d) A valid daily (24-hour) value shall be the arithmetic average of at least 18 of the possible 24 hourly values during a day (12 midnight to 12 midnight E.S.T.).

(e) A valid annual average shall be the arithmetic average of at least 65 percent of the possible hourly values, uniformly distributed throughout the calendar year. Less values could be used to compute means, provided it can be shown by acceptable statistical analysis that these means are valid estimates.]

[H. Location of Measurements. Measurements of air pollutants may be made at any place where air pollution could exist.]

A. Definitions and Reference Conditions. For the purposes of §§B—G, below, the definitions, reference conditions, and methods of measurement are specified in 40 CFR Parts 50 and 53, 1977 Edition, 43 FR 46258-46261 (October, 1978) and 44 FR 8202 (February 8, 1979).

B. Sulfur Oxides.

(1) The primary ambient air quality standards for sulfur oxides, measured as sulfur dioxide are:

(a) 80 micrograms per cubic meter (.03 ppm)—annual arithmetic mean;

(b) 365 micrograms per cubic meter (.140 ppm)—maximum 24-hour concentration not to be exceeded more than once per year.

(2) The secondary ambient air quality standard for sulfur oxides, measured as sulfur dioxide, is 1300 micrograms per cubic meter (.50 ppm)—maximum 3 hour concentration not to be exceeded more than once per year.

C. Particulate Matter.

(1) The primary ambient air quality standards for particulate matter are:

(a) 75 micrograms per cubic meter—annual geometric mean;

(b) 260 micrograms per cubic meter—maximum 24-hour concentration not to be exceeded more than once per year.

(2) The secondary ambient air quality standard for particulate matter is 150 micrograms per cubic meter—maximum 24-hour concentration not to be exceeded more than once per year.

D. Carbon Monoxide.

The primary and secondary ambient air quality standards for carbon monoxide are:

(1) 10 milligrams per cubic meter (8 ppm)—maximum 8-hour concentration not to be exceeded more than once per year;

(2) 40 milligrams per cubic meter (35 ppm)—maximum 1-hour concentration not to be exceeded more than once per year.

E. Ozone. The primary and secondary ambient air quality standards for ozone is 235 micrograms per cubic meter (.12 ppm)—the standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above .12 ppm is equal to or less than one.

F. Hydrocarbons. The primary and secondary ambient air quality standard guideline for hydrocarbons is 160 micrograms per cubic meter (.24 ppm)—maximum 3-hour concentration (6 to 9 a.m.) not to be exceeded more than once per year.

G. Nitrogen Dioxide. The primary ambient air quality standard for nitrogen dioxide is 100 micrograms per cubic meter (.05 ppm)—annual arithmetic mean.

H. Lead. The primary and secondary ambient air quality standards for lead are 1.5 micrograms per cubic meter—maximum arithmetic mean averaged over a calendar quarter.

I. [Secondary] Ambient Air Quality Standards for Fluorides.

(1) Ambient air quality standards for fluorides [at the more adverse level shall be] *are* those concentrations in the ambient air *or in other substances* which result in the following values being exceeded:

(a)—(i) (text unchanged)

[(2) Air Pollution Control Measures to be Required. When concentrations of fluoride cause any of the values set forth in (1), above, to be exceeded, the application of all necessary means shall be required for reducing the concentrations. The means to be required and the time schedule for their implementation shall be based on the premise that fluoride concentrations are to be reduced progressively in the shortest possible time to levels that will not cause the values in (1), above, to be exceeded.]

[(3)] *(2)* (text unchanged)

TABLES 1—3 (text unchanged)

[TABLE 4

AMBIENT AIR QUALITY STANDARDS

Pollutant	Frequency	More Adverse Range				Serious Level		Conversion Factor
	Times Values May Be Exceeded per Unit Time	UG/M³ Lower Limit	UG/M³ Upper Limit	PPM Lower Limit	PPM Upper Limit	UG/M³	PPM	
(1) Sulfur oxides (expressed as sulfur dioxide concentrations) Annual arithmetic average[1]	Values not to be exceeded	60	79	0.023	0.03	79	0.03	$\frac{UG/M^3}{2620}$ = PPM
Daily average	Once per year					262	0.10	
One hour average	Once per month					920	0.35	
(2) Particulate matter (a) Suspended particulate Annual arithmetic average		65	75	—	—	75	—	
Daily average	Once per year	140	160	—	—	160	—	
(b) Dustfall Annual arithmetic average	Values not to be exceeded	MG/CM²/Month 0.35	0.50			MG/CM²/month 0.50		$\frac{MG/CM^2}{035}$ = TON/MI²
Monthly average		Lower limit 0.70	Upper limit 1.00			1.0		
(3) Carbon monoxide 8-hr arithmetic average[2]	Once per year	No standard				$\frac{MG/M^3}{10}$	$\frac{PPM}{9}$	MG/M³ × 0.873 = PPM
Hourly average	Once per year	No standard				40	35	
(4) Non-methane hydrocarbons[3] three-hour average[4]	Once per year	No standard				$\frac{UG/M^3}{160}$	$\frac{PPM\ carbon}{0.24}$	$\frac{UG/M^3}{655}$ = PPM
(5) Photochemical oxidants hourly average	Once per year	No standard				$\frac{UG/M^3}{160}$	$\frac{PPM\ ozone}{0.08}$	$\frac{UG/M^3}{1960}$ = PPM
(6) Nitrogen dioxide annual arithmetic average	Values not to be exceeded	No standard				$\frac{UG/M^3}{100}$	$\frac{PPM}{0.05}$	$\frac{UG/M^3}{1882}$ = PPM

References

(1) Annual averages shall be for the calendar year for all pollutants.

(2) Applies in areas representing generalized atmospheric levels; 20 PPM applies in any other place where members of the public congregate for extended periods of time.
(3) The standards set forth in this regulation for hydrocarbons are not based upon the direct adverse effects of hydrocarbons but upon an empirical relationship, based upon ambient air quality measurements, between morning hydrocarbon concentrations and oxidant concentrations occurring later the same day. The hydrocarbon standard is designed primarily to achieve the standard for photochemical oxidants. In view of the lack of an exact quantitative relationship, the uncertainties in existing measurement techniques and a lack of full identification of the photochemically reactive species of hydrocarbons occurring in the ambient air in the region, these levels should be considered as tentative pending further scientific developments.
(4) Three hour period: 6 a.m. to 9 a.m. Eastern Standard Time.]

10.18.02 Control of Air Pollution in Area I

10.18.03 Control of Air Pollution in Area II

10.18.06 Control of Air Pollution in Area V

10.18.07 Control of Air Pollution in Area VI

.02 Control and Prohibition of Visible Emissions.

[A. For the purpose of these regulations:

(1) "Existing installation or equipment" means those erected before January 17, 1972, or such other date as specified in these regulations.

(2) "Modified installation or equipment" means those altered, changed, or added to on or after January 17, 1972, or such other date as specified in these regulations.

(3) "New Plant" means any installation for which the major proportion of the fuel burning, incineration, processing or manufacturing equipment in the installation was erected on or after January 17, 1972 or such other date as specified in these regulations. This definition is not intended to apply to a "modified installation" or equipment where new control equipment is added to an existing installation. In questionable cases, the determination of new plants shall be made by the Department.]

[B. Visible Emissions from New Plants. A person shall not cause or permit the discharge of emissions from any plant or building erected on or after January 17, 1972, other than water in an uncombined form, which is visible to human observers.]

[C. Visible Emissions from Existing and Modified Installations.

(1) Existing and Modified Bituminous Concrete Manufacturing Plants. A person shall not cause or permit the discharge of emissions from any existing or modified bituminous concrete manufacturing installation other than water in an uncombined form, which are visible to the human observer.

(2) Other Existing and Modified Installation. A person shall not cause or permit emissions from any other existing or modified installation or building that are darker in shade or appearance than that designated as No. 1 on the Ringelmann Smoke Chart or greater than 20 percent opacity.]

A. A person may not cause or permit the discharge of emissions from any installation, other than water in an uncombined form, which is greater than 20 percent opacity.

[D.] *B.* Exceptions.

(1) [§§B and C] *§A* does not apply to emissions during the building of a new fire, cleaning of fires, soot blowing, start-up and process modifications or adjustments, or occasional cleaning of control equipment, which are not [darker in shade or appearance than that designated as No. 2 on the Ringelmann Smoke Chart or not] greater than 40 percent opacity for a period [or periods aggregating no more than 4 minutes in any sixty minutes.] *of no more than 6 consecutive minutes in any 60 minutes.*

[(2) Any person who believes that meeting the requirements of §B is not practical in a particular instance may request an exception to the requirements of §B. Such a request shall be submitted to the Department in writing and include evidence to show why compliance is not practical. Upon the receipt of a request for an exception, the Department shall schedule a public hearing to be held within 60 days. The applicant for the exception shall advertise the hearing prominently at least 30 days prior to the hearing date, by notice in a newspaper of general circulation in the subdivision in which the facility or source for which the exception is sought is located. The notice shall include the name of the facility or source and any additional information the Department may require. Based upon the evidence presented at the hearing the Secretary may grant an exception to §B for a period not to exceed 5 years under other terms and conditions that are appropriate to reduce the impact of the exception.]

(2) Exceptions to Requirements of §A.

(a) Any person who believes that meeting the requirements of §A, above, is not practical or technologically feasible in a particular instance may request an exception to the requirements of §A. The request shall be submitted to the Department in writing and shall include evidence indicating why compliance is not practical or not technologically feasible. Upon receipt of this request, the Department will schedule a public hearing to be held within 60 days to consider the request for an exception. The Department will give at least 30 days notice in the Maryland Register by announcing the purpose, date, time, and place of the hearing. The applicant shall advertise the hearing for the exception prominently at least 30 days before the hearing date by notice in a newspaper of general circulation in the subdivision in which is located the facility or source for which the exception is sought. The notice shall contain the same information as the notice published in the Maryland Register. Based upon the evidence presented in the request and at the public hearing, the Secretary, or his designated hearing officer, will make a finding as to the practicality or technical feasibility of compliance with §A. If the Secretary or his designated hearing officer finds that compliance is not practical or is not technologically feasible, he will grant an exception to §A.

(b) In making his determination, the Secretary or his designated hearing officer will take into consideration all evidence relating to the practicality or technological feasibility of compliance, including evidence of source hardship and economic burden, cost-effectiveness, and social, environmental, and economic consequences.

(c) Upon granting an exception, the Secretary or his designated hearing officer will establish an opacity standard applicable to the building or installation receiving the exception which he finds is practical and technologically feasible. Exceptions may not be granted for a period of more than 5 years, and may be renewed.

(3) (text unchanged)

(4) [Exceptions] The Control Officer may grant exceptions to [paragraph .02C] *§A*, above, under the following conditions.

(a)—(b) (text unchanged)
[E.] *C.*—[F.] *D.* (text unchanged)

.03 Control and Prohibition of Particulate Matter Emissions.

A. (text unchanged)

B. Control of Particulate Matter from Fuel Burning Equipment.

(1) (text unchanged)

(2) [New] *Existing* Fuel Burning Equipment. [(a)] A person may not cause or permit particulate matter caused by the combustion of fuel [oil] in any fuel burning equipment erected [after] *before* January 17, 1972, to be discharged into the atmosphere in excess of the amounts shown in [Table 1] *Figure 1*.

[(b) A person shall not cause or permit particulate matter caused by combustion of solid fuel in any fuel burning equipment erected after January 17, 1972, to be discharged into the atmosphere in excess of the amounts shown in Table 1.]

[(c) Dust collection Devices Required on New Fuel Burning Equipment.

(i) A person shall not cause or permit the combustion of residual fuel oil in any fuel burning equipment erected after January 17, 1972 with a maximum heat input of 13 million BTU/hour (13.7 gigajoules/hour) or more unless such equipment is fitted with a dust collector which is so designed that it reasonably may be expected to produce sufficient dust particle force residence time and particulate retention to satisfy the requirements of Table 1.

(ii) A person shall not cause or permit the combustion of solid fuel in any fuel burning equipment erected after January 17, 1972 unless such equipment is so designed that it reasonably may be expected to produce sufficient dust particle force, residence time and particle retention to satisfy the requirements of Table 1.]

[(3) Existing and Modified Fuel Burning Equipment. A person shall not cause or permit particulate matter caused by the combustion of fuel in existing or modified fuel burning equipment to be discharged from any stack or chimney into the atmosphere in excess of the hourly rate set forth in the following table.

Heat Input in Million BTU Per Hour (Gigajoules Per Hour)	Maximum Allowable Discharge of Particulate Matter in Pounds Per Million BTU (Grams/Gigajoule) from Existing and Modified Fuel Burning Equipment
Up to and Including 10 (10.55)	0.60 (258)
10,000 and Greater (10,550)	0.12 (51.6)

For a heat input between the heat inputs stated in the preceding table, maximum allowable discharge of particulate matter is shown for existing and modified fuel burning equipment in Figure 1. For these purposes, heat input shall be calculated as the aggregate heat content of all fuels whose products of combustion pass through the stack or chimney.]

(3) New Fuel Burning Equipment. A person may not cause or permit particulate matter caused by the combustion of fuel in any fuel-burning equipment erected on or after January 17, 1972, to be discharged from any stack or chimney into the atmosphere in excess of the amounts shown in Figure 2.

(4) Exceptions.

(a) [Interruptible gas service. Fuel burning equipment burning gas with an interruptible gas service is exempt from the provisions of (2) and (3).]

[(b)] The Control Officer may grant exceptions to [paragraph (3)] *§B(2)*, above, under the following conditions:

(i) When the application of [paragraph (3)] *§B(2)* to a residential building housing two or less families creates undue economic hardship on individuals residing therein; or,

(ii) (text unchanged)

[(c)] *(b)* Fuel burning installations on ships are exempt from the provisions of *this regulation.*

C. Particulate Matter from [Incineration Plants and Installations] *Incinerators.*

[(1) Incineration Plants erected on or after January 17, 1972.

(a) A person shall not cause or permit to be discharged into the atmosphere particulate matter to exceed 0.10 gr/SCFD (229 mg/dscm) from any new incinerator plant that has a burning capacity less than 1 ton (907 kilograms) of refuse per hour and is used to burn less than 5 tons (4540 kilograms) of refuse per day.

(b) A person shall not cause or permit to be discharged into the atmosphere particulate matter to exceed 0.03 gr./SCFD (69 mg/dscm) from any new incineration plant other than pathological that has a burning capacity equal to or greater than 1 ton (907 kilograms) of refuse per hour or is used to burn 5 tons (4540 kilograms) or more of refuse per day.

(c) A person shall not cause or permit to be discharged into the atmosphere particulate matter to exceed 0.10 gr/SCFD (229 mg/dscm) from any new pathological incineration plant. Medical waste may be burned in such units, provided that the unit has been approved for that purpose by the Department.]

[(2)] *(1)* Existing [and Modified Incineration Installations] *Incinerators.* A person may not cause or permit to be discharged into the outdoor atmosphere from any [existing or modified] incinerator *erected before January 17, 1972*, the following:

(a) From any existing [or modified] incinerator burning less than 200 pounds (90.7 kilograms) of refuse per hour, particulate matter to exceed .3 gr/SCFD (687 mg/dscm).

(b) From any existing [or modified] incinerator burning 200 (90.7 kilograms) or more pounds of refuse per hour, particulate matter to exceed .2 gr/SCFD (458 mg/dscm).

[(c) From any existing or modified pathological incinerator, particulate matter to exceed .3 gr/SCFD (687 mg/dscm). Medical waste may be burned in such units, provided that the unit has been approved for that purpose by the Department.]

(2) New Incinerators. A person may not cause or permit particulate matter to be discharged from any incinerator erected on or after January 17, 1972, in excess of .10 gr/SCFD (229 mg/dscm).

D. (text unchanged)

[E. Particulate Matter from Other Plants and Installations.]

[(1) Other New Plants Erected on or after January 17, 1972.

(a) A person shall not cause or permit to be discharged into the outdoor atmosphere from any other new process plant, particulate matter in excess of 0.03 gr/SCFD (69 mg/dscm).

(b) The maximum allowable weight of particulate matter discharged per hour from any other new process plant shall not exceed that determined from Table 2. Where the process weight per hour falls between two values in the table, the maximum weight discharged per hour shall be determined by linear interpolation. When the process weight exceeds 60,000 pounds per hour (27,200 kilograms per hour) the maximum allowable weight discharged per hour will be determined by the use of the following equation:

$E = 55.0\ P^{0.11} - 40$	($E = 11.79\ P^{0.11} - 18.14$
E = Maximum weight discharged per hour (lbs.)	E = Maximum weight discharged per hour (kg)
P = Process weight rate in tons per hour	P = Process weight in kilograms per hour)

This limitation shall supersede the requirements of subparagraph .03E(1)(a) if it requires a lower emission rate per hour.]

[(2) Other Existing and Modified Process Installations.

(a) Existing and Modified Bituminous Concrete Manufacturing Installations. A person shall not cause or permit to be discharged into the atmosphere from any existing or modified bituminous concrete manufacturing installation particulate matter in excess of 0.03 gr/SCFD (69 mg/dscm).

(b) Other Existing and Modified Installations.

(i) The maximum allowable weight of particulate matter discharged per hour from any other existing or modified process installation shall not exceed that determined from Table 2. Where the process weight per hour falls between two values in the table, the maximum weight discharged per hour shall be determined by linear interpolation. When the process weight exceeds 60,000 pounds per hour (27,200 kilograms per hour) the maximum allowable weight discharged per hour will be determined by use of the following equation:

$E = 55.0\ P^{0.11} - 40$	($E = 11.79\ P^{0.11} - 18.14$
E = Maximum weight discharged per hour (lbs.)	E = Maximum weight discharged per hour (kg)
P = Process weight rate in tons per hour	P = Process weight rate in kilograms per hour)

(ii) For those processes in which the process weight per hour exceeds 60,000 pounds (27,200 kilograms) the maximum allowable weight of particulate matter discharged per hour may exceed that calculated by the above equation providing that the concentration of particulate matter in the gases discharged to the atmosphere is less than 0.05 gr/SCFD (115 mg/dscm).]

E. Particulate Matter from Asphalt Concrete Plants. A person may not cause or permit particulate matter to be discharged from any asphalt concrete plant constructed before June 11, 1973, in excess of .05 gr/SCFD (92 kg/dscm).

F. Particulate Matter from Other Installations.

(1) Existing Other Installations. A person may not cause or permit particulate matter to be discharged from any other installation constructed before January 17, 1972, in excess of the values determined from Table 1. If the process weight per hour falls between two values in the table, the maximum weight discharged per hour shall be determined by linear interpolation. If the process weight exceeds 60,000 pounds (27,200 kilograms) per hour, the maximum allowable weight discharged per hour will be determined by the use of the following equation:

$E = 55.0\ P^{0.11} - 40$	($E = 11.79\ P^{0.11} - 18.14$
E = Maximum weight discharged per hour (lbs.)	*E = Maximum weight discharged per hour (kg)*
P = Process weight in tons per hour	*P = Process weight in kilograms per hour)*

For those processes in which the process weight per hour exceeds 60,000 pounds (27,200 kilograms), the maximum allowable weight of particulate matter discharged per hour may exceed that calculated by the above equation providing that the concentration of particulate matter in the gases discharged to the atmosphere is less than .05 gr/SCFD (115 mg/dscm).

(2) New Other Installations. A person may not cause or permit particulate matter to be discharged from any other installation constructed on or after January 17, 1972, in excess of .05 gr/SCFD (115 kg/dscm).

(3) Exception. For any premise for which the Department determines that compliance with §F(2) will cause or exacerbate a violation of the National Ambient Air Quality Standards or federal Prevention of Significant Deterioration increments, the applicable emission standard is .03 gr/SCFD (229 mg/dscm).

[F.] *G.* (text unchanged)

.04 Control and Prohibition of Gas and Vapor Emissions.

A. (text unchanged)

B. 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 the following limitations:

(1) (text unchanged)

(2) [On and after July 1, 1975, residual] *Residual* fuel oil, 2.0 percent.

(3) Distillate fuel oils, .3 percent.

(4) Process gas used as a fuel, .3 percent.

C. (text unchanged)

D. Exceptions.

(1)—(4) (text unchanged)

(5) For any premise located in Area I, for which the Department determines that compliance with §B(1) and (2), above, will cause or exacerbate a violation of the National Ambient Air Quality Standards or federal Prevention of Significant Deterioration of Air Quality increments, the applicable emission standard is as follows:

(a) For solid fuel, 1.8 pounds oxides of sulfur per million Btu (.75 kilogram per gigajoule) actual heat input per hour.

(b) For residual oil, 1.0 percent sulfur content by weight.

E.—F. (text unchanged)

G. Nitrogen Oxides from New Fuel Burning Equipment.

(1) A person may not cause or permit the discharge of nitrogen oxides into the atmosphere, from any fuel burning equipment built after May 12, 1972, having a heat input rating of 250 million BTU (264 gigajoules) per hour, or more, in excess of the following rates:

(a)—(b) (text unchanged)

(c) [0.50] *.70* pounds per million BTU ([215] *318* gm per gigajoule) heat input, maximum 2-hour average, expressed as NO_2 when solid fuel is burned.

(2) (text unchanged)

H. (text unchanged)

I. Hydrocarbons from Other Than Fuel-Burning Equipment.

(1) Definitions.

(a) (text unchanged)

(b) "True vapor pressure" means the absolute pressure in pounds per square inch (kiloneutons per square meter) determined at storage conditions. Storage conditions shall be taken as the average monthly temperature. If the storage is subject to solar and ambient heat gain only, the temperature shall be taken as the average monthly temperature, to a maximum average of 77°F (25°C) (average storage temperature for the months of May through September). True vapor pressure shall be determined by measurement at the storage conditions or by the use of a nomograph, published by the Coordinating Research Council and include with these regulations as Figure [2] *3*, relating true vapor pressure to Reid Vapor Pressure and storage temperature.

(2) (text unchanged)

J. (text unchanged)

.06 Control and Prohibition of Installations and Operations.

A.—C. (text unchanged)

D. Prohibition of Certain New Fuel Burning Equipment.

(1) (text unchanged)

(2) A person may not construct fuel burning equipment designed for use of solid fuel in which any individual furnace has a rated heat input of less than [50] *13* million BTU ([52.8] *13.7* gigajoules) per hour.

(3)—(4) (text unchanged)

E. (text unchanged)

Table 1: Deleted in its entirety.

Table [2] *1*.

Table [2B] *1B*.

Figure 1: Deleted in its entirety.

Figure 1: See following figure.

FIGURE 1

Maximum Allowed Discharge of Particulate Matter From Existing Fuel Burning Equipment
(Equipment Built Before January 17, 1972)

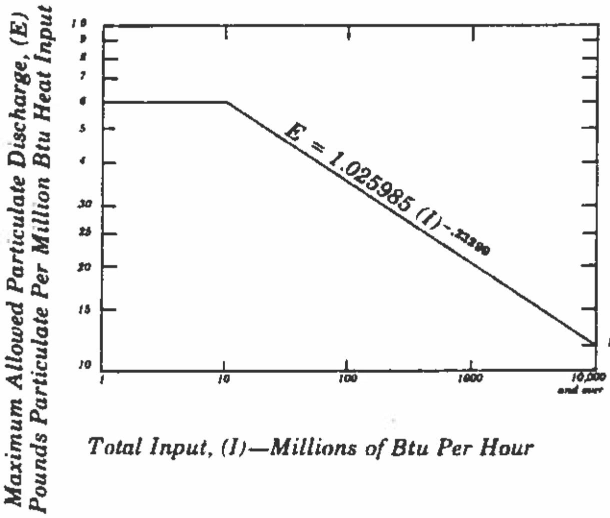
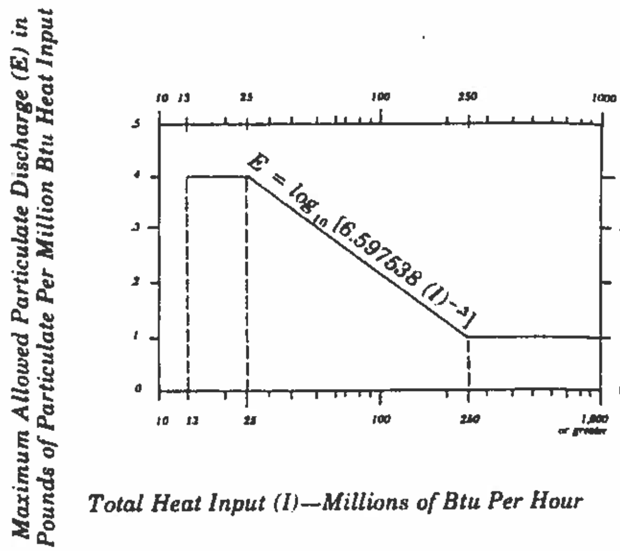


Figure 2: See following figure.

FIGURE 2

Maximum Allowed Discharge of Particulate Matter From New Fuel Burning Equipment
(Equipment built after January 17, 1972)



Notes: 1. The construction of new solid and residual oil fuel burning equipment under 13 MM Btu (13.7 gigajoules) per hour is prohibited under COMAR 10.18.02.06D, 10.18.03.06D, 10.18.06.06D, and 10.18.07.06D.

2. New fuel burning equipment over 250 MM Btu (263.8 gigajoules) per hour are regulated by NSPS source regulations COMAR 10.18.02.05, 10.18.03.05, 10.18.06.05, and 10.18.07.05.

3. Depending on load factor, fuel ash content and control equipment, fuel burning equipment which has a heat input greater than approximately 25 MM Btu (26.4 gigajoules) per hour may be subject to Prevention of Significant Deterioration Review (40 USC Part 52.21) and consequent additional control requirements.

Figure [2.] *3*.

10.18.04 Control of Air Pollution in Area III

10.18.05 Control of Air Pollution in Area IV

.04 Control and Prohibition of Gas and Vapor Emissions.

A. (text unchanged)

B. 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 the following limitations.

(1)—(3) (text unchanged)

[(4) On and after July 1, 1980, residual fuel oil, 0.5 percent.]

[(5)] *(4)* Sulfur Content Limitations For Coke Ovens.

(a)—(c) (text unchanged)

[(d) After June 30, 1983, the plant-wide average in any 2-hour period, of the sulfur content by weight of coke oven gas used as fuel from coke ovens constructed before the effective date of this regulation, may not exceed that permitted in residual fuel oils.]

C.—F. (text unchanged)

G. Nitrogen Oxides from Fuel Burning Equipment.

(1) New Fuel Burning Equipment Erected On or After May 12, 1972. A person may not cause or permit the discharge of nitrogen oxides into the atmosphere, from any new fuel burning equipment having a heat input rating of 250 million BTU (264 gigajoules) per hour or more, in excess of the following rates:

(a)—(b) (text unchanged)

(c) [0.50] *.70* pounds ([215] *318* gm) per million BTU (gigajoules) heat input maximum 2-hour average, expressed as NO_2 when solid fuel is burned.

(2)—(3) (text unchanged)

H.—K. (text unchanged)

CHARLES R. BUCK, JR.
Secretary
Department of Health and Mental Hygiene

[Md. R. Doc. No. 79-696. Filed at Div. of St. Doc. Apr. 23, 1979. Filed at AELR Comm. Apr. 24, 1979.]

Subtitle 19 DANGEROUS DEVICES AND SUBSTANCES

10.19.04 Prescription Drugs—Products Selection

Authority: Article 43, §273A, Annotated Code of Maryland

Notice of Proposed Action

The Environmental Health Administration proposes to adopt the amendment to Regulation **.02 Interchangeable Drug Products,** printed below, to be effective in August, 1979.

These regulations prohibit the substitution or interchanging of a critical-dose drug, tolbutamide tablets.

Estimate of Economic Impact

The proposed action has no economic impact.

Opportunity for Public Comment

The Environmental Health Administration will hold a hearing concerning the adoption of these regulations August 1, 1979, 9:30 a.m., in the 3rd Floor Conference Room, 201 West Preston Baltimore, Maryland 21201. All interested persons are invited to attend and give their views.

Written comments may be sent to Raymond A. Huber, Regulations Coordinator, O'Conor Building, Room 314-A, 201 West Preston Street, Baltimore, Maryland 21201. These comments must be received no later than the date of the hearing.

.02 Interchangeable Drug Products.

A.—PPP. (text unchanged)

QQQ. Tolbutamide Tablets.

	[500 mg.]	[Promo Pharm.]
Orinase	500 mg.	Upjohn

RRR.—XXX. (text unchanged)

CHARLES R. BUCK, JR.
Secretary
Department of Health and Mental Hygiene

[Md. R. Doc. No. 79-634. Filed at Div. of St. Doc. Apr. 12, 1979. Filed at AELR Comm. Apr. 12, 1979.]

Title 11 DEPARTMENT OF TRANSPORTATION

Subtitle 01 OFFICE OF THE SECRETARY

11.01.06 Transportation Planning Process

Authority: Transportation Article, §2-103, Federal-Aid Highway Program Manual, Volume 7, Chapter 7, §1, promulgated under authority of §109 (h), Title 23, U.S.C.

Notice of Proposed Action

The Department of Transportation proposes to adopt the amendment printed below to the "Maryland Action Plan, Revised Chapter V—Highway Project Development (Maryland Department of Transportation, April, 1977)", under **COMAR 11.01.06.01, The "Action Plan",** to be effective on June 29, 1979. Specifically, the Department is proposing to amend Chapter V, Section E—Project Design (Phase III & IV), R/W Relocation Assistance Statement Approval. This change would remove a self-imposed requirement for Federal Highway Administration approval of pre-acquisition relocation plan design approval.

Estimate of Economic Impact

The proposed action has no economic impact.

Opportunity for Public Comment

No public hearing is scheduled. Interested parties may submit views or comments to Gary L. Rosenbaum, Office of Transportation Planning, Department of Transportation, P.O. Box 8755, Baltimore-Washington International Airport, Maryland 21240, on or before June 5, 1979.

.01 The "Action Plan."

Ed. Note. Pursuant to Article 41, §256H(a), Annotated Code of Maryland, "Maryland Action Plan, Revised Chapter V, Highway Project Development (Maryland Department of Transportation, April 1977)" was incorporated by reference at 4:26 Md. R. 2025 (December 16, 1977). A copy of this document is filed at each of the public repositories listed in 5:16 Md. R. 1303—1306 (August 11, 1978) and at the Division of State Documents, 11 Bladen Street, Annapolis, Maryland.

Subtitle 22 BOARD OF COSMETOLOGISTS

09.22.01 Types of Licensure: Privileges of and Limitations on Licensees

Authority: Article 43, §544,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 3, 1979, an amendment to Regulation .15 under **COMAR 09.22.01 Types of Licensure: Privileges of and Limitations on Licensees,** was adopted by the State Board of Cosmetologists.

This amendment, which was proposed for adoption in 6:11 Md. R. 984 (June 1, 1979), has been adopted as proposed. This becomes effective coincident with the date of this issue of the Maryland Register.

EUNICE R. ALPER
Executive Director

[Md. R. Doc. No. 79-1686. Filed at Div. of St. Doc. Oct. 9, 1979.]

Subtitle 22 BOARD OF COSMETOLOGISTS

09.22.02 Schools of Beauty Culture—Types of Licensure, Application, Requirements, Curriculum, Limitations on Licensees

Authority: Article 43, §536(e) and 544,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 3, 1979, amendments to Regulation **.16, .19,** and **.20,** under **COMAR 09.22.02 Schools of Beauty Culture—Types of Licensure, Application, Requirements, Curriculum, Limitations on Licensees,** were adopted by the State Board of Cosmetologists.

These amendments, which were proposed for adoption in 6:11 Md. R. 984—985 (June 1, 1979) have been adopted as proposed. They become effective coincident with the date of this issue of the Maryland Register.

EUNICE R. ALPER
Executive Director

[Md. R. Doc. No. 79-1685. Filed at Div. of St. Doc. Oct. 9, 1979.]

Title 10 DEPARTMENT OF HEALTH AND MENTAL HYGIENE

Subtitle 18 AIR QUALITY

10.18.01 Control of Air Pollution in the State

10.18.02 Air Pollution in Area I

10.18.03 Air Pollution in Area II

10.18.04 Air Pollution in Area III

10.18.05 Air Pollution in Area IV

10.18.06 Air Pollution in Area V

10.18.07 Air Pollution in Area VI

Authority: Article 43, §§690 through 706,
Annotated Code of Maryland

Notice is given that on October 9, 1979, amendments to Regulation **.03 Air Pollution Episode System,** and Regulation **.04 Ambient Air Quality Standards,** under **COMAR 10.18.01 Control of Air Pollution in the State;** Regulations **.02 Control and Prohibition of Visible Emissions, .04 Control and Prohibition of Gas and Vapor Emissions,** and **.06 Control and Prohibition of Certain New Fuel Burning Equipment** under **COMAR 10.18.02 Air Pollution in Area I, COMAR 10.18.03 Air Pollution in Area II, COMAR 10.18.06 Air Pollution in Area V,** and **COMAR 10.18.07 Air Pollution in Area VI;** and Regulation **.04 Control and Prohibition of Gas and Vapor Emissions,** under **COMAR 10.18.04 Air Pollution in Area III,** and **COMAR 10.18.05 Air Pollution in Area IV;** were adopted by the Department of Health and Mental Hygiene, Charles R. Buck, Jr., Secretary.

These amendments which were proposed for adoption in 6:9 Md. R. 739—747 (May 4, 1979), have been adopted as proposed and will become effective on December 10, 1979.

In the notice of hearing which appeared in 6:9 Md. R. 739 (May 4, 1979), eight companies were identified that would not be permitted to take advantage of the proposed relaxation to the sulfur in fuel content and four companies were identified that would not be permitted to take advantage of the proposed relaxation to the particulate emissions standard. Based on the information presented at the hearings, those lists have been modified. The following sources will be required to continue burning 1 percent sulfur fuels: Celanese Corporation; Kelly-Springfield Tire Company; Potomac Edison Company; Fairchild Republic; Mack Trucks, Inc. The following sources will be required to continue meeting the particulate emissions standard of 0.03 gr/SCFD: Kelly-Springfield Company (buffers, tire tread grinders); Eastalco Aluminum Company (potline electro-cells, carbon anode furnace); D. M. Stoltzfus and Sons (stone crushing).

CHARLES R. BUCK, JR.
Secretary of Health and Mental Hygiene

[Md. R. Doc. No. 79-1710. Filed at Div. of St. Doc. Oct. 10, 1979.]

Title 10
DEPARTMENT OF HEALTH AND MENTAL HYGIENE

Subtitle 27 BOARD OF EXAMINERS OF NURSES

10.27.06 Practice of Nurse Anesthetist

Authority: Article 43, §290—302,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 10, 1979, Regulations .01—.09, under **COMAR 10.27.06 Practice of Nurse Anesthetist,** were adopted by the Secretary of the Department of Health and Mental Hygiene.

These regulations, which were proposed for adoption in 6:2 Md. R. 87—88 (January 26, 1979), have been adopted as proposed. They become effective December 1, 1979.

CHARLES R. BUCK, JR.
Secretary of Health and Mental Hygiene

[Md. R. Doc. No. 79-1705.]

Title 11
DEPARTMENT OF TRANSPORTATION

Subtitle 01 OFFICE OF THE SECRETARY

11.01.11 Small Business Procurements, Construction Contracts

Authority: Article 41, §231, G-2,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on October 1, 1979, amendments to Regulations **.02 Definitions, .03 Small Business Contractor List,** and **.04 Small Business Set-aside,** under **COMAR 11.01.11 Small Business Procurements, Construction Contracts,** were adopted by the Secretary of Transportation.

These amendments, which were proposed for adoption in 6:16 Md. R. 1351—1352 (August 10, 1979), have been adopted as proposed. They become effective coincident with the date of this issue of the Maryland Register.

JAMES J. O'DONNELL
Secretary of Transportation

[Md. R. Doc. No. 79-1647. Filed at Div. of St. Doc. Oct. 2, 1979.]

Subtitle 03 STATE AVIATION ADMINISTRATION

11.03.04 Aeroneautical Regulations

Authority: Transportation Article, §5-204(d)(4),
and Chapter 190, Acts of 1976,
Annotated Code of Maryland

Notice of Final Action

Notice is given that, on September 11, 1979, amendments to Regulations .05, .10, and .11, under **COMAR 11.03.04 Aeronautical Regulations,** were adopted by the State Aviation Administrator.

These amendments, which were proposed for adoption in 6:15 Md. R. 1290 (July 27, 1979), have been adopted as proposed. They become effective coincident with the date of this issue of the Maryland Register.

KARL R. SATTLER
State Aviation Administrator

[Md. R. Doc. No. 79-1637. Filed at Div. of St. Doc. Sept. 28, 1979.]

Subtitle 04 STATE HIGHWAY ADMINISTRATION

11.04.09 Bicycles

Authority: Transportation Article, §21-1205.1(b)(3),
Annotated Code of Maryland

Notice of Final Action

Notice is given that on September 25, 1979, new Regulation **.01 Smooth Surface,** under **COMAR 11.04.09 Bicycles,** was adopted by the Administrator of the State Highway Administration.

This new regulation, which was proposed for adoption in 6:16 Md. R. 1352 (August 10, 1979), has been adopted as proposed. It becomes effective coincident with the date of this issue of the Maryland Register.

M. S. CALTRIDER
State Highway Administrator

[Md. R. Doc. No. 79-1633. Filed at Div. of St. Doc. Sept. 27, 1979.]

SECTION 2. AND BE IT FURTHER ENACTED, That this Act shall take effect July 1, 1978.

Approved May 29, 1978.

CHAPTER 1005

(House Bill 1164)

AN ACT concerning

Air Quality Control Standards

FOR the purpose of ~~providing utility bill savings to Maryland citizens while maintaining air quality at levels fully adequate to protect the health, general welfare, and property of the people of the State;~~ requiring certain regulations of the Department of Health and Mental Hygiene governing ambient air quality to be identical to national air quality standards; requiring that certain emission standards be established for certain stationary sources; and providing a transition period for the promulgation of regulations ~~; and requiring that all fuel cost savings consequently realized by public service companies be fully applied to reduce electric bills rendered to customers.~~

BY repealing

Article 43 - Health
Section 693(b)
Annotated Code of Maryland
(1971 Replacement Volume and 1977 Supplement)

BY adding to

Article 43 - Health
Section 691(h) and (i), and 693(b)
Annotated Code of Maryland
(1971 Replacement Volume and 1977 Supplement)

SECTION 1. BE IT ENACTED BY THE GENERAL ASSEMBLY OF MARYLAND, That section(s) of the Annotated Code of Maryland be repealed, amended, or enacted to read as follows:

Article 43 - Health

691.

For the purposes of this Subtitle:

(H) "EMISSION STANDARD" MEANS A REQUIREMENT WHICH LIMITS THE QUANTITY, QUALITY, RATE, OR CONCENTRATION OF EMISSIONS FROM A SOURCE , INCLUDING REQUIREMENTS RELATING TO THE OPERATION OR MAINTENANCE OF THE SOURCE TO ASSURE CONTINUOUS EMISSION REDUCTION.

(I) "SECRETARY" MEANS THE SECRETARY OF HEALTH AND MENTAL HYGIENE.

693.

[(b) The Department shall prepare and submit to the Board for approval not later than June 1, 1968, regulations establishing standards for emissions into the air and the ambient air quality for each of the areas authorized by subsection (a) of this section.

The governing body of any local jurisdiction within any area may request the Department to recommend to the Board for adoption a regulation establishing more restrictive standards for emissions or ambient air quality to be applicable within its geographic area.]

(B) (1) THE DEPARTMENT SHALL ~~PREPARE AND SUBMIT TO THE BOARD FOR APPROVAL~~ PROMULGATE REGULATIONS ESTABLISHING STANDARDS FOR EMISSIONS INTO THE AIR AND THE AMBIENT AIR QUALITY FOR EACH OF THE AREAS AUTHORIZED BY SUBSECTION (A) OF THIS SECTION.

(2) THE GOVERNING BODY OF ANY LOCAL JURISDICTION WITHIN ANY AREA MAY REQUEST THE DEPARTMENT TO ADOPT MORE RESTRICTIVE STANDARDS FOR EMISSIONS OR AMBIENT AIR QUALITY TO BE APPLICABLE WITHIN ITS GEOGRAPHIC AREA.

(3) WITH REGARD TO AMBIENT AIR QUALITY, EXCEPT AS PROVIDED IN §693(B)(2), STANDARDS FOR POLLUTANTS SHALL BE ESTABLISHED BY THE DEPARTMENT AND SHALL BE IDENTICAL TO THE STANDARDS FOR POLLUTANTS FOR WHICH NATIONAL PRIMARY OR SECONDARY AMBIENT AIR QUALITY STANDARDS ARE PRESCRIBED AND ADOPTED BY THE FEDERAL ENVIRONMENTAL PROTECTION AGENCY OR ANY OTHER FEDERAL AGENCY ACTING PURSUANT TO §109 ET. SEQ. OF THE FEDERAL CLEAN AIR ACT OR OTHER APPLICABLE FEDERAL LEGISLATION.

(4) THE DEPARTMENT IN ORDER TO PROTECT THE HEALTH, GENERAL WELFARE, AND PROPERTY OF THE PEOPLE OF THE STATE MAY ESTABLISH AMBIENT AIR QUALITY STANDARDS FOR SUBSTANCES FOR WHICH NO NATIONAL AMBIENT AIR QUALITY STANDARDS HAVE BEEN PROMULGATED. STATE AMBIENT AIR QUALITY STANDARDS MAY INCLUDE MAXIMUM CONCENTRATION OF POLLUTANTS IN SUBSTANCES OTHER THAN AIR IF THE SECRETARY DETERMINES THAT TRANSPORTATION THROUGH THE AIR IS A SIGNIFICANT FACTOR IN THE BUILDUP OF THE POLLUTANT IN THE SUBSTANCE AND IF THE SECRETARY DETERMINES THAT MONITORING OF THE SUBSTANCE OTHER THAN AIR FACILITATES THE CONTROL OF THE POLLUTANT.

(5) ALL AMBIENT AIR QUALITY STANDARDS PREVIOUSLY PROMULGATED WHICH ARE INCONSISTENT WITH THIS

REQUIREMENT ARE REPEALED TO THE EXTENT OF THE INCONSISTENCY.

(6) ~~FOR~~ EXCEPT AS PROVIDED IN PARAGRAPH (2) OF THIS SUBSECTION (B), FOR AREAS WHERE ATTAINMENT OF AMBIENT AIR QUALITY STANDARDS HAS BEEN ACHIEVED THE ESTABLISHING OF STATE EMISSION STANDARDS SHALL BE BASED ON THE GOAL OF ACHIEVING EMISSION LEVELS WHICH ARE NO MORE RESTRICTIVE THAN REQUIRED TO ATTAIN AND MAINTAIN THE AMBIENT AIR QUALITY STANDARDS REVISED PURSUANT TO PARAGRAPH (3) OF THIS SUBSECTION (B), EXCEPT WHERE NEW SOURCE PERFORMANCE STANDARDS ~~OR~~, NATIONAL PREVENTION OF SIGNIFICANT DETERIORATION ~~STATUTES~~ REQUIREMENTS, OR NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS , OR ANY OTHER REQUIREMENTS OF THE FEDERAL CLEAN AIR ACT ARE APPLICABLE.

(7) FOR THOSE EMISSIONS FOR WHICH NO AMBIENT AIR QUALITY STANDARDS HAVE BEEN ADOPTED PURSUANT TO PARAGRAPH (3) OF THIS SUBSECTION (B), ~~SUCH AS VISIBLE EMISSIONS AND ODORS,~~ THE SECRETARY MAY ESTABLISH EMISSION STANDARDS AND REQUIREMENTS FOR ABATEMENT OF AIR POLLUTION FOR THE VARIOUS CLASSES OF SOURCES.

(8) ALL EMISSION REGULATIONS PREVIOUSLY PROMULGATED WHICH ARE INCONSISTENT WITH ~~THESE REQUIREMENTS~~ PARAGRAPH (6) OF THIS SUBSECTION (B) SHALL BE REPEALED TO THE EXTENT OF THE INCONSISTENCY NOT LATER THAN JULY 1, 1979.

~~(9) ALL SAVINGS IN FUEL COSTS WHICH ARE REALIZED BY MARYLAND PUBLIC SERVICE COMPANIES DUE TO REVISED AMBIENT AIR QUALITY STANDARDS AND REVISED AIR EMISSION STANDARDS SHALL BE APPLIED IN TOTO TO REDUCE UTILITY BILLS RENDERED TO CONSUMERS IN ACCORDANCE WITH ARTICLE 78, §54D. THE MECHANISM EMPLOYED FOR THIS PURPOSE SHALL BE THE FUEL RATE ADJUSTMENT CLAUSE IN TARIFFS FILED BY EACH UTILITY COMPANY WITH THE PUBLIC SERVICE COMMISSION.~~

SECTION 2. AND BE IT FURTHER ENACTED, That this Act shall take effect July 1, 1978.

Approved May 29, 1978.

CHAPTER 1006

(House Bill 1326)

AN ACT concerning

Public Information Act

FOR the purpose of eliminating unnecessary definitions; adding and revising definitions; providing a policy statement; ~~allowing~~ ~~directing~~ providing that State and local governments ~~to~~ may maintain only necessary and relevant information about persons under certain

~~22~~ companies (8)
57 pieces (25)

TABLE II List of Amendment Affected Sources

8 not allowed (25-eg)
1 not in compliance (3-eg)

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF 0.1%[1]	OIL GR	MBTU /HR	CONTROL EQUIP[2]	SO2 LBS/HR	SO2 LBS/D	SO2 TONS/YR	HRS /D	DAYS /YR	STACK HT-FT[3]
1	219 604	11	WESTVACO	O	5	70	8	6	338		163.71	3929.0	667.94	24	340	600
1	219 604	11	WESTVACO	C	18	0	30	0	590	ESP	1838.42	44122.1	7500.75	24	340	600
1	219 604	11	WESTVACO	C	19	0	24	0	785	MCY ESP	2281.25	54750.0	9307.50	24	340	600
1	304 666	13	CELANESE CORPORATION	B	53	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	13	CELANESE CORPORATION	G	54	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	13	CELANESE CORPORATION	G	55	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	13	CELANESE CORPORATION	B	56	71	0	6	276		38.33	919.9	167.89	24	365	120
1	304 666	14	KELLY-SPRINGFIELD TIRE	O	2	0	8	6	135		60.44	1450.6	226.29	24	312	200
1	304 666	14	KELLY-SPRINGFIELD TIRE	C	108	49	15	6	180	ESP	565.44	13570.6	2117.01	24	312	262
1	304 666	14	KELLY-SPRINGFIELD TIRE	C	109	49	15	6	180	ESP	565.44	13570.6	2117.01	24	312	262
1	310 643	5	PPG INDUSTRIES, INC.	C	10	56	10	0	64	MCY	41.83	1003.9	183.22	24	365	100
1	310 643	5	PPG INDUSTRIES, INC.	C	11	56	10	0	64	MCY	41.83	1003.9	183.22	24	365	100
1	310 643	5	PPG INDUSTRIES, INC.	C	12	56	10	0	64		8.67	208.1	37.97	24	365	100
21	568 644	5	POTOMAC EDISON CO.	C	5	0	10	0	382	ESP	224.87	5396.9	971.44	24	360	177
21	568 644	5	POTOMAC EDISON CO.	C	6	71	10	0	710	ESP	1364.05	32737.2	5892.70	24	360	201
21	568 664	75	BYRON, W.D. & SONS	O	103	71	8	6	25		31.39	251.1	31.39	8	250	~~100~~ 150
21	568 664	75	BYRON, W.D. & SONS	O	104	71	8	6	25		31.39	251.1	31.39	8	250	~~100~~ 150
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	C	51	65	10	0	36	MCY	25.70	77.1	6.94	3	180	50
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	C	52	65	10	0	86	MCY	425.83	1277.5	114.97	3	180	50
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	C	53	65	10	0	100	MCY	385.27	1155.8	104.02	3	180	50
21	597 624	127	MD. CORRECT. INST. - HAGERSTOWN	O	141	65	8	5	3		6.77	20.3	1.83	3	180	1
21	597 659	13	ROPER EASTERN	O	9	0	8	5	21		6.84	54.7	7.11	8	260	30
21	597 659	17	VICTOR HOSIERY CORP.	O	16	68	8	5	9		8.60	68.8	8.94	8	260	30
21	597 659	22	COLOMBO INC.	O	20	65	8	6	8		.35	2.8	.36	8	260	1
21	597 659	22	COLOMBO INC.	O	21	65	8	6	8		.35	2.8	.36	8	260	1
21	597 659	23	MANBECK BREAD CO.	O	22	0	8	4	6		1.40	11.2	1.46	8	260	1
21	597 659	72	MARYLAND MACHINE & FOUNDRY	O	76	58	8	4	1		.70	5.6	.73	8	260	30
21	597 659	90	GRAY CONCRETE	O	86	51	8	4	6		3.21	25.7	3.29	8	256	30
21	597 659	91	BEACHLEY FURNITURE	O	87	68	8	4	8		1.05	8.4	1.09	8	260	30
21	597 659	125	HAGERSTOWN POST OFFICE	O	135	65	8	5	2		3.37	10.1	.91	3	180	50
21	597 659	130	HAGERSTOWN MUNICIPAL LT. PLANT *	O	144	0	8	6	60		.14	1.1	.18	8	315	50
21	597 659	130	HAGERSTOWN MUNICIPAL LT. PLANT *	O	162	57	10	6	195	MCY	101.15	2427.6	382.35	24	315	150
21	597 659	130	HAGERSTOWN MUNICIPAL LT. PLANT *	O	163	57	10	6	195	MCY	101.15	2427.6	382.35	24	315	150
21	597 662	84	JAMISON DOOR - MAPLE AVE.	O	83	56	8	5	4		5.63	45.0	5.86	8	260	1
21	597 682	104	FAIRCHILD REPUBLIC	O	95	41	8	6	19	MCY	7.76	124.2	15.52	16	250	50
21	597 682	104	FAIRCHILD REPUBLIC	O	96	41	8	6	19	MCY	7.76	124.2	15.52	16	250	50
21	597 682	104	FAIRCHILD REPUBLIC	O	97	44	8	6	40	MCY	15.97	255.5	31.94	16	250	50
21	597 682	104	FAIRCHILD REPUBLIC	O	98	44	8	6	40	MCY	15.97	255.5	31.94	16	250	50
21	600 660	6	MACK TRUCKS	O	6	0	8	6	140		19.65	157.2	20.44	8	260	50
21	600 660	6	MACK TRUCKS	O	7	0	8	6	140		19.65	157.2	20.44	8	260	50

733 · 2800 x 243
Robert A. Kelley

AREA 1

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	EQUIP NO	YR INST	SULF 0.1%	OIL GR	MBTU /HR	CONTROL EQUIP	SO2 LBS/HR	SO2 LBS/D	SO2 TONS/YR	HRS /D	DAYS /YR	STACK HT-FT
21	600 660	6	MACK TRUCKS	O	8	0	8	6	140		19.65	157.2	20.44	8	260	50
21	600 660	74	GILBERT INDUSTRIES	O	78	62	8	4	5		4.38	35.0	4.38	8	250	30
21	602 656	99	SUPREME CONCRETE BLOCK	O	92	61	8	5	5		5.98	47.8	6.22	8	260	30
21	639 664	1	DOUBLEDAY & CO.	O	1	0	8	6	3		1.71	27.4	3.46	16	253	28
21	639 664	1	DOUBLEDAY & CO.	O	2	0	8	6	3		1.71	27.4	3.46	16	253	28
21	662 684	123	FORT RITCHIE	O	109	60	8	5	5		5.40	16.2	1.46	3	180	50
21	662 684	123	FORT RITCHIE	O	110	60	8	5	5		5.40	16.2	1.46	3	180	50
21	662 684	123	FORT RITCHIE	O	111	67	8	5	3		6.77	20.3	1.83	3	180	30
21	662 684	123	FORT RITCHIE	O	112	64	8	5	3		4.07	12.2	1.10	3	180	30
21	662 684	123	FORT RITCHIE	O	113	64	8	5	2		5.40	16.2	1.46	3	180	30
21	662 684	123	FORT RITCHIE	O	115	57	8	5	6		10.80	32.4	2.92	3	180	50
21	662 684	123	FORT RITCHIE	O	116	57	8	5	8		4.07	12.2	1.10	3	180	50
21	662 684	123	FORT RITCHIE	O	119	57	8	5	4		8.80	26.4	2.38	3	180	50
21	662 684	123	FORT RITCHIE	O	120	57	8	5	4		3.37	10.1	.91	3	180	50
21	662 684	123	FORT RITCHIE	O	122	57	8	5	4		3.37	10.1	.91	3	180	30
21	662 684	123	FORT RITCHIE	O	124	57	8	5	9		14.87	44.6	4.01	3	180	50
21	662 684	123	FORT RITCHIE	O	125	66	8	5	4		7.43	22.3	2.01	3	180	30

NOTE:
1. O: Oil-burning equipment, C: Coal-burning equipment, G: Gas-burning equipment
2. ESP: Electrostatic precipitator, MCY: Multicyclone
3. 1:0-30'

* Not in operation at present

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF 0.1%[1]	OIL GR	MBTU /HR	CONTROL EQUIP[2]	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK HT-FT[3]
1	219 604	11	WESTVACO	P	32	72	0	0	0	DIS	21.47	515.3	87.60	24	340	200
1	219 604	11	WESTVACO	P	33	72	0	0	0	DIS	21.47	515.3	87.60	24	340	200
1	271 683	149	MT. SAVAGE SPECIAL REFRACTORIES	P	31	76	0	0	0	BAG	.22	1.8	.18	8	200	0
1	286 666	101	INTERSTATE AMIESITE CORP.	P	12	71	3	0	0	BAG	3.42 ~~.43~~	~~3.4~~ 27.4	~~.34~~ 2.74	8	200	30
1	304 666	13	CELANESE CORPORATION	P	63	75	0	0	0	BAG	1.29	31.0	5.65	24	365	50
1	304 666	13	CELANESE CORPORATION	P	66	75	0	0	0	BAG	1.29	31.0	5.65	24	365	50
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	60	73	0	0	0	SPR	.06	1.4	.19	24	260	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	69	76	0	0	0	SCR	.83	19.9	3.11	24	312	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	70	77	0	0	0	CYC	.05	1.2	.19	24	312	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	71	77	0	0	0	CYC	.83	19.9	3.11	24	312	0
1	304 666	14	KELLY-SPRINGFIELD TIRE	P	72	77	0	0	0	CYC	.83	19.9	3.11	24	312	0
1	304 666	29	CUMBERLAND CONTRACTING COMPANY	P	10	0	3	0	0	SCR	4.06 ~~[illegible]~~ ~~5.07~~	~~40.6~~ 32.4	~~1.65~~ 2.7	8	180	30
1	304 666	90	LILLER BROTHERS ASPHALT COMPANY	P	11	70	2	0	0	MCY	6.69 ~~.84~~	~~6.7~~ 53.5	~~.50~~ 4.01	8	150	30
11	120 582	2	GARRETT COUNTY ROADS ASPHALT PLANT	P	23	75	3	0	0	BAG	.67	5.4	.54	8	200	30
11	120 582	34	BROWNING FOODLAND	I	2	73	0	0	0		.46	2.3	.36	5	312	49
11	149 615	3	LAUREL FORK CO.	P	22	61	3	0	0	SCR	4.28 ~~.53~~	~~4.2~~ 34.2	~~.34~~ 2.74	8	160	30
21	467 682	131	RALOC	P	90	73	0	0	0	BAG	.18	1.4	.18	8	250	0
21	467 682	131	RALOC	P	91	73	0	0	0	BAG	.55	4.4	.55	8	250	0
21	467 682	131	RALOC	P	93	73	0	0	0	BAG	.36	2.9	.36	8	250	0
21	558 655	115	MARTIN MARRIETTA - PINESBURG	P	24	73	0	0	0	BAG	.55	4.4	.55	8	250	0
21	558 655	115	MARTIN MARRIETTA - PINESBURG	P	31	73	0	0	0	BAG	.55	4.4	.55	8	250	0
21	568 664	75	BYRON, W.D. & SON	I	30	77	0	0	0		.15	3.6	.56	24	312	37
21	595 650	155	CONSERVIT, INC.	P	35	75	0	0	0	CYC	7.76	62.1	6.21	8	200	0
21	597 659	8	MARQUETTE CEMENT	P	87	77	0	0	0	BAG	3.08	73.9	13.49	24	365	100
21	597 659	8	MARQUETTE CEMENT	P	88	77	0	0	0	BAG	1.75	42.0	7.66	24	365	100
21	597 659	8	MARQUETTE CEMENT	P	89	77	0	0	0	BAG	.42	10.1	1.84	24	365	100
21	597 659	114	CRAIG, O.O.	P	19	63	3	0	0	SCR	1.27	10.2	1.45	8	286	1
21	597 659	114	CRAIG, O.O.	P	36	78	3	2	0	BAG	.97	7.8	1.09	8	280	30
21	597 659	132	BLAINE WINDOW HARDWARE	P	95	74	0	0	0	BAG	.18	1.4	.18	8	250	1
21	597 659	132	BLAINE WINDOW HARDWARE	P	96	74	0	0	0	BAG	.18	1.4	.18	8	250	1
21	597 659	132	BLAINE WINDOW HARDWARE	P	97	74	0	0	0	BAG	.18	1.4	.18	8	250	0
21	597 659	132	BLAINE WINDOW HARDWARE	P	98	74	0	0	0	BAG	.18	1.4	.18	8	250	0
21	598 662	67	BESTER-LONG, INC.	P	111	76	0	0	0	SCR	3.53 ~~.44~~	~~3.5~~ 28.2	~~.39~~ 3.11	8	220	1
21	598 662	67	BESTER-LONG, INC.	P	112	76	0	0	0	SCR	2.10 ~~.26~~	~~2.1~~ 16.8	~~.23~~ 1.85	8	220	30
21	616 610	96	KLINE, RICHARD F. INC.-BOONSBORO	P	67	64	8	0	0	SCR	6.38 ~~.80~~	~~6.4~~ 51.0	~~.32~~ 2.55	8	100	50
21	631 657	107	PLUMMER CONSTRUCTION CO.	P	76	69	2	0	0	BAG	2.28 ~~.29~~	~~2.3~~ 18.2	~~.19~~ 1.46	8	160	30

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	SULF[2] 0.1%	OIL GR	MBTU /HR	CONTROL[2] EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK[3] HT-FT
10	640 610	106	MYERSVILLE SCHOOL	I	36	72	0	0	0	BUR	1.33	4.0	.36	3	180	30
10	650 587	149	MIDDLETOWN MIDDLE SCHOOL	I	48	76	0	0	0	BUR	.51 ~~1.50~~	2.03 ~~6.0~~	.18 ~~.54~~	4	180	4
10	677 583	131	FORT DETRICK	I	49	76	0	0	0	SCR	2.63	42.1	5.47	~~16~~ (7)	260	60 decrease waste
10	677 583	131	FORT DETRICK	I	50	76	0	0	0	SCR	2.63	42.1	5.47	~~16~~ (7)	260	60
10	678 546	5	EASTALCO ALUMINUM	P	53	75	0	0	0	BAG	60.71	1457.0	265.91	24	365	30
10	678 546	5	EASTALCO ALUMINUM	P	54	75	0	0	0	BAG	60.71	1457.0	265.91	24	365	30
10	678 546	5	EASTALCO ALUMINUM	P	64	75	8	0	0	SCR	8.87	212.9	38.85	24	365	30
10	685 576	26	ETZLER, N.W., CO.	P	34	73	0	0	0	BAG	2.97	23.8	2.38	8	200	50
10	685 576	29	CAMPBELL-GROVE,FRED,PLANT1	P	7	78 69	0	0	0	BAG	.44	10.6	1.65	24	312	1
10	685 576	29	CAMPBELL-GROVE,FRED,PLANT1	P	11	72	0	0	0	BAG	.83	19.9	2.19	24	220	30
10	685 576	29	CAMPBELL-GROVE,FRED,PLANT1	P	18	72	0	0	0	OTH	7.02	112.3	16.06	16	286	0
10	685 576	37	KLINE, RICHARD F., INC. (A)	P	33	73	8	0	0	BAG	6.16	49.3	4.93	8	200	30
10	685 576	78	NORTH FREDERICK ELEMENTARY	I	57	77	0	0	0	BUR	.50	2.0	.18	4	180	4
10	689 652	81	THURMONT ELEM.	I	19	76	0	0	0	BUR	1.53	6.1	.55	4	180	4
10	700 544	83	URBANA ELEM.	I	53	76	0	0	0	BUR	.50	2.0	.18	4	180	4
10	701 601	160	WALKERSVILLE HIGH SCHOOL	I	54	76	0	0	0	BUR	.50	2.0	.18	4	180	4
10	708 682	66	EMMITSBURG ELEM.	I	46	74	0	0	0	BUR	.50	2.0	.18	4	180	4
10	712 627	51	MILLER, C.J., INC. (A) 0.014	P	53	75	3	0	0	BAG	2.05	16.4	1.64	8	200	30
10	716 538	107	GREENVALLEY SCHOOL	I	37	72	0	0	0	BUR	1.33	4.0	.36	3	180	30
10	724 565	76	NEW MARKET ELEM.	I	56	78	0	0	0	BUR	.50	2.0	.18	4	180	4

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS	AREA EQUIP NO	YR INST	SULF[5] 0.1%	OIL GR	MBTU /HR	CONTROL EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK HT-FT
8	754 279	40	NAVAL ORDNANCE STA.-INDIAN HEAD	I	7 6	77 76	0	0	0		5.07 .88	30.4 3.53	.18 .18	6 4	~~72~~ 104	32 45
8	826 288	1	ARUNDEL ASPHALT PRODUCTS (A)	P	1	69	10	0	0	BAG	1.61 ~~.20~~	~~1.6~~ 12.9	~~.18~~ 1.46	8	225	30
8	826 288	12	~~D & R CO.~~ Anthony Contractors, Inc. (A)	P	5 6	76 71	3	0	0	SCR	4.18 ~~3.43~~	~~27.4~~ 33.5	~~3.29~~ 4.02	8	240	1
8	845 263	44	CARRUTH & SON, INC.	P	1	76	0	0	0	DIS	1.49	11.9	1.82	8	306	0
18	873 221	21	ASHER CORP.	P	2	75	0	0	0	BAG	.91	7.37	.73	8	200	1
18	923 187	5	DEAN CONSTRUCTION CO. (A)	P	1	65	7	0	0	SCR	2.05	16.4	1.64	8	200	30
18	923 187	5	DEAN CONSTRUCTION CO. (A)	P	2	74	3	0	0	BAG	2.28	18.2	1.82	8	200	30

CO	MD GRID (X, Y)	PREM NO	PREMISE NAME	CLASS[1]	AREA EQUIP NO	YR INST	6 SULF 0.1%	OIL GR	MBTU /HR	CONTROL[2] EQUIP	TSP LBS/HR	TSP LBS/D	TSP TONS/YR	HRS /D	DAYS /YR	STACK[3] HT-FT
7	1060 630	9	FIRESTONE PLASTICS	P	21	75	0	0	0	BAG	2.85	68.4	12.24	24	358	0
7	1060 630	9	FIRESTONE PLASTICS	P	22	75	0	0	0	BAG	2.85	68.4	12.24	24	358	50
7	1122 628	15	MITCHELL, STEWART E. INC. (A)	P	3	63	3	0	0	SCR	3.65 ~~.46~~	~~3.7~~ 29.2	~~.18~~ 1.46	8	100	30
7	1130 667	3	STOLTZFUS & SONS	P	15	72	0	0	0	OTH BAG	.21	1.7	.18	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	16	72	0	0	0	OTH BAG	5.18	41.4	4.56	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	17	72	0	0	0	BAG	.21	1.7	.18	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	18	72	0	0	0	BAG	2.90	23.2	2.55	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	19	72	0	0	0	BAG	2.07	16.6	1.82	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	24	72	0	0	0	BAG	.63	5.0	.55	8	220	0
7	1130 667	3	STOLTZFUS & SONS	P	25	72	0	0	0	BAG	2.90	23.2	2.55	8	220	0
9	1063 270	79	ZAPATA HAYNIE	P	7	77	0	0	0	OIS	8.30	66.4	.73	8	22	0
9	1068 270	15	COLDWATER SEAFOOD CORP.	P	39	73	0	0	0	SCR	.67	5.4	.54	8	200	30
9	1107 281	70	TUBMAN, GROVER JACK	I	3	73	0	0	0		.47	1.4	.18	3	260	11
9	1120 301	64	INTERSTATE AMIESITE CORP. (A)	P	4	71	3	0	0	SCR	4.79 ~~.60~~	~~4.8~~ 38.3	~~.48~~ 3.83	8	200	30
17	1073 490	6	BRAMBLE DAVID A. (A)	P	1	0	3	0	0	SCR	4.56 ~~.57~~	~~4.6~~ 36.5	~~.41~~ 3.28	8	180	30
19	1175 138	49	CELLUTRON PRODUCTS	P	4	77	0	0	0	BAG	2.29	55.0	8.57	24	312	0
20	1059 342	40	BRAMBLE DAVID A. (A)	P	1	0	3	0	0	SCR	0.76 ~~.09~~	~~.7~~ 6.1	~~.06~~ .55	8	180	50
20	1063 345	55	BLACK & DECKER MFG.	P	6	75	0	0	0	BAG	.19	1.5	.18	8	243	0
22	1195 199	26	H.D. METAL CO., INC.	P	17	72	0	0	0	BUR	4.38	35.0	4.38	8	250	30
22	1196 180	34	CROWN CORK & SEAL CO., INC.	P	35	72	0	0	0	BUR	.10	2.4	.37	24	312	50
22	1196 180	89	NICHOLS, S.E. DEPT. STORE	I	14	73	0	0	0	BUR	.58	4.6	.72	8	312	27
22	1203 197	86	HICKORY RIDGE FOODS	P	34	72	0	0	0	SPR	.22	1.8	.18	8	200	1
22	1203 197	94	HOFFMAN-LAROCHE, INC.	P	36	74	0	0	0	BAG	.88	7.0	1.10	8	312	1
22	1208 228	8	INTERSTATE AMIESITE CORP. (A)	P	40	75	3	0	0	SCR	4.11	32.9	3.29	8	200	30
23	1212 66	51	ELLER, LANCE J. INC.	P	6	72	3	0	0	SCR	7.07	56.6	5.66	8	200	30
23	1315 189	10	EASTERN ANIMAL FOODS	P	47	77	0	0	0	SCR	.05	1.2	.18	24	300	0

NOTE:

1. P: Process, I: Incinerator
2. BAG: Baghouse, BUR: Afterburner, CYC: Cyclone, SCR: Scrubber, SPR: Sprayer, MCY: Multicyclone, OIS: Other Inertia Scrubber, OTH: Other
3. 1:0-30', 0:stack height not applicable--rooftop vent, etc.

TABLE III

PREDICTIONS OF MAXIMUM CONCENTRATION INCREMENTS
FOR THOSE PREMISES WHICH EXCEED PSD INCREMENTS
OR NATIONAL AMBIENT AIR QUALITY STANDARDS
(Concentration increment shown are due to the impact
of all sources at a particular premise)

Source	Pollutant	Maximum Concentration Increments (ug/m^3) 3-hour	24-hour	Annual	Distance (km)	Stability	Windspeed (m/s)	Remarks
Celanese	SO_2		243	61	1.1 (WSW)	E	2.5	Terrain Impingement
Kelly-Springfield	SO_2	363	161	13	1.6 (south)	F	1.0	Terrain Impingement
	TSP	----	71	2[a]	.4	F	2.5	Downwash
PPG	SO_2	419	186	4	2.4 (ENE)	F	1.0	Terrain Impingement
Westvaco	TSP	----	299	14[a]	.5 (NW)	F	1.0	Terrain Impingement
Potomac Edison*	SO_2	1477	696		.7	A	3.0	
Byron & Son*	SO_2	331	147		.4	B	1.0	Downwash
Md. Corr. Inst.*	SO_2	426	190		.5	A	3.0	
Fairchild*	SO_2	2581	1147		.4	F	2.5	Downwash
Mack*	SO_2	228	102		.4	B	1.0	Downwash
Eastalco	TSP	----	113	7[a]	.8	E	2.5	Downwash
Stoltzfus	TSP	----	67		.4	C	2.0	

* Annual increment not given, since these were modeled together.

a Arithmetic average

NOTE: Federal PSD increments for Class II areas may be found in Table I.

TABLE IV

Description of SO_2 Sources Predicted to Exceed PSD Increments or NAAQS

Premise Name	Type of Fuel-Burning Equipment	MM BTU Size	Maryland Registration No.	PSD Violation	Standard Violation	Remarks
Celanese	4 gas/oil boilers	276 276 276 276	01-71-5-00053 01-71-5-00054 01-71-5-00055 01-77-5-00056	24-hr., Ann	24-hr	NUS Report 1978 (1 coal-Unit 5, 1 oil)
Kelly-Springfield	2 coal boilers	180 180	01-49-3-00108 01-49-3-00109	3, 24-hr, Ann	3, 24-hr	
	1 oil boiler	135	01-69-4-00002			
PPG Industries	3 coal boilers	64 64 64	01-56-3-00010 01-56-3-00011 01-56-3-00012 Standby	24-hr	24-hr ---	
Potomac Edison	2 coal boilers	382 710	21-00-3-00005 21-71-3-00006	3,24-hr	3,24-hr	
W. D. Byron & Son	2 oil boilers	25 25	21-71-4-00103 21-71-4-00104	24-hr	---	@400m, B-stability, 1 m/sec, downwash
Md. Correc. Inst.	3 coalbboilers	36 86 100	21-65-3-00051 21-65-3-00052 21-65-3-00053	24-hr	---	
	1 oil boiler	3	21-65-4-00141			
Fairchild Republic	4 oil boilers	19 19 40 40	21-44-4-00095 21-44-4-00096 21-44-4-00097 21-44-4-00098	3,24-hr	3,24-hr	@400m, F-stability 2.5 m/sec, downwash
Mack Trucks	3 oil boilers	140 140 140	21-00-4-00006 21-00-4-00007 21-00-4-00008	24-hr	---	@400m, B-stability 1 m/sec, downwash

TABLE V

Description of TSP Sources Predicted to Exceed PSD Increments or NAAQS

Premise Name	Type of Process	Control Equipment	Maryland Registration No.	PSD Violation	Standard Violation	Remarks
				Date of Appl, Starting Date, Date of Completion		
Westvaco	2 smelt dissolving tanks on No. 3 recovery boiler	Mesh pad scrubber	01-72-7-00032	24-hour	24-hour	
		Mesh pad scrubber	01-72-7-00033	?	Annual	
Kelly-Springfield	Rubber buffing (tire balancing)	Type W rotoclone	01-73-6-00060	24-hour 3-5-73	24-hour 3-19-73	@400m, F-stability 2.5 m/sec, downwash
	Hand buffer station for tire repair buffing line	Dry centrifugal rotoclone	01-77-6-00070	3-22-77, 3-28-77, 5-6-77		@800m, no PSD violation
	3 Goodyear force-grind tire tread grind machines	Cyclone	01-76-6-00069	5-26-76, 4-19-76, 5-28-76		
		Cyclone	01-77-6-00071	7-21-77, 7-29-77, 8-19-77		
		Cyclone	01-77-6-00072	8-1-77, 6-17-77, 7-18-77		
Eastalco	"B" potline (Electrolytic-cells)	Baghouse	10-75-7-00053	9-17-73, 9-19-73, 12-1-75, 8-1-75 (Date operation) " 24-hour	" 24-hour,	" Downwash "
		Baghouse	10-75-7-00054		Annual	
	"B" Carbon Anode Furnace	Scrubber	10-75-7-00064	10-17-73, 11-15-73, 5-1-75		
Stoltzfus & Sons	4848 Universal Jaw Crusher	Baghouse & Sprays	07-74-9-00015	Appl date 24-hour 8-1-74,	Date of operation 24-hour 9-1-72	@400m, C-stability 2 m/sec
	36FC Gyrasphere Crusher	Baghouse & Sprays	07-74-9-00016	8-1-74	9-1-72	
	1051AC Hydracone Crusher	Baghouse	07-74-9-00018	8-1-74	9-1-72	
	48FC Gyrasphere Crusher	Baghouse	07-74-9-00019	8-1-74	9-1-72	
	4895 Telsmith Gyra Crusher	Baghouse	07-74-9-00024	8-10-74	9-1-72	
	48FC Telsmith Gyra Crusher	Baghouse	07-74-9-00025	8-10-74	9-1-72	

BACKGROUND

Morgantown Generating Station is engaged in the generation of electric energy. The primary SIC code for this plant is 4911. The major components of the facility consist of two (2) steam units primarily firing bituminous coal, four (4) auxiliary boilers firing on No. 2 fuel oil, six (6) combustion turbines firing on No. 2 fuel oil and their associated fuel storage and handling equipment. The gross winter capacity of the facility is 1580 MW.

Each of the two (2) boilers, manufactured by Combustion Engineering (CE) is rated at 640 MW. Each boiler is a tangentially coal fired supercritical unit with a superheater, single reheat and economizer. Units 1 and 2 are each equipped with Low NO_X burners (LNBs), Electrostatic Precipitators (ESP), Selective Catalytic Reduction (SCR), Over Fire Air (OFA) and Flue Gas Desulfurization (FGD) and exhausted through a 400 foot high stack. When the FGD systems are not in use, the flue gas is exhausted through a 700 foot high by-pass stack. The Units also have the capability of firing on No. 6 oil as an alternative primary fuel.

Three (3) auxiliary boilers are CE (Model No.30 VP-12W) package boilers each rated at 164 MMBtu/hr and one (1) auxiliary boiler is a CE (Model No.30VP2180R/48) rated at 219.3 MMBtu/hr. These auxiliary boilers fire No. 2 oil and are used for start-up steam and space heating.

Combustion Turbines CT-1 and CT-2 are General Electric (GE) Frame-5 each rated at 20 MWs and fired on No. 2 fuel oil. These CTs are both used for blackstart and peaking purposes. Combustion Turbines CT-3, 4, 5 and 6 are GE Frame -7 each rated at 65 MW and fired on No. 2 fuel oil. These CTs are used for peaking purposes.

A coal barge unloader system, a gypsum barge loading system, a coal blending-system and a fly-ash beneficiation facility (STAR) are also located at the station.

The following table summarizes the actual emissions from Morgantown Generating Station based on its Annual Emission Certification Reports:

Table 1: Actual Emissions

Year	NO_X (TPY)	SO_X (TPY)	$PM_{10}/PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	Total HAP (TPY)
2016	949	2826	162/70	496	61	81
2015	897	2781	135/28	442	54	72
2014	1323	2998	197	625	76	103
2013	731	2475	232/108	394	38	62

The major source threshold for triggering Title V permitting requirements in Charles County is 25 tons per year for NO_X and VOCs, 100 tons per year for any other criteria pollutant, and 10 tons per year of any single hazardous air pollutant (HAP) or 25 tons per year of any combination of HAPs. Since actual emissions of NO_X, SO_X, VOC, PM_{10} and CO are greater than the major source threshold, Morgantown Generating Station is required to obtain a Title V Part 70 Operating Permit under COMAR 26.11.03.01.

The Department, on October 2, 2012, received the Morgantown 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 November 1, 2012 granting Morgantown Generating Station an application shield. The Permit was issued on October 1, 2015.
The Permit is being amended in response to Environmental Integrity Project (EIP) petition and is also being renewed.

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 Morgantown Generating Station:

Changes based on the EIP Petition

- Removal of all references to the March 2008 Consent Decree from the Federal section of the Permit. It's a State-only requirement.
- Correction of the typo for the PM value from 1.4 to 0.14 pounds/million Btu of heat input. The value is based on the Figure 1 of the COMAR 26.11.09.09. Equation is $E = 1.025985\ (I)^{-.23299}$.
  Where Total Input (I) – Millions of Btu per hour
- Update the Testing, Monitoring and Record-keeping and Reporting Requirements for Control of Visible Emissions and Control of Particulate Matter.

Changes based on Maryland SIP approval

On June 29, 2017, the COMAR 26.11.38-Control of Nitrogen Oxide Emissions from Coal-fired Electric Generating Units was SIP approved. Therefore, the requirements were moved to the federal section of the permit.

Additions to the facility

On January 30, 2009, GenOn received a CPCN (Case No. 9148) for a Coal Blending System and Gypsum Barge Unloading System. [**017-0014-6-0154 & 017-0014-6-0153**]. The Gypsum Barge Unloading System commenced operation on December 30, 2009. The north yard of the coal blending system commenced operation April 12, 2010 and the south yard commenced operation on December 17, 2010.

On August 29, 2007, GenOn received a CPCN (Case No.9085) for a FGD System to control emissions from Units F1 and F2. The FGD System commenced operation in December 2009.

On January 31, 2011, GenOn received a CPCN (Case No. 9229) for a STAR Facility. [**6-0150**]. the facility commenced operation on January 4, 2012. On February 5, 2013, an administrative change issued to address Condition A-7g of the CPCN adding a duration period for SO_2 emissions. "Compliance shall be determines by applying a 24-hour block average."

On March 22, 2017, an administrative change to Morgantown's CPCN #9148 (Coal Blending/Gypsum Barge Load Out) was approved by Maryland Public Service Commission to include Dickerson as an authorized source of gypsum to be transported through the barge load out facility.

Removal from the facility
Synthetic Fuel manufacturing facility (6-0115) was removed in 2007.

Name Change
Effective December 14, 2012, NRG Energy, Inc. (NRG) and GenOn Energy, Inc. (GenOn) combined and retained the name NRG Energy, Inc. As a result of the merger, all GenOn entities became wholly owned subsidiaries of NRG. The legal entity for Morgantown remains GenOn Mid-Atlantic, LLC.
On January 25, 2011, Mirant 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.

MACT and NSPS
Morgantown Generating Station is a major source of HAPs and is subject to the following MACT standards (40 CFR Part 63):

1. Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (F1 and F2)
2. Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (F-Aux1 through F-Aux4).

Morgantown Generating Station is subject to NSPS (40 CFR Part 60), Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (F-Aux2).

Morgantown Generating Station is subject to the NO_X Reasonably Available Control Technology (RACT) requirements, Acid Rain Program, and the Cross State Air Pollution Rule (CSAPR). Morgantown 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_X Annual Trading Program, subparts BBBBB- NO_X Ozone Season Trading Program, and subpart CCCCC SO_2 Group 1 Trading Program.

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 F1 and F2 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.

Morgantown Generating Station conducted a Compliance Assurance Monitoring (CAM) analysis for the facility and determined that only the particulate matter emissions from Units F1and F2 boilers by-pass stack are subject to CAM requirements. The renewal application was submitted to the Department with a CAM analysis for particulate matter emissions from Units F1 and F2 boilers by-pass stacks.

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 UUUUU, 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 oil-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.

Morgantown 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).

Morgantown 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 Morgantown Generating Station must meet, are presented below and in the permit.

The MATS rule reduces emission 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_2) may also be a surrogate for HCl, if the EGU has a flue gas desulfurization (FGD) system. Morgantown’s two EGUs has CEM systems that continuously monitor emissions including PM, SO_2 and Hg. Emissions monitored by these CEMS will be used to demonstrate compliance with the MATS rule by calculating the 30-boiler operating day arithmetic averages. Morgantown began and continues collecting PM, SO_2 and Hg data since September 12, 2015. The MATS rule also requires EGUs to startup and shutdown on a clean fuel; therefore Morgantown EGUs startup and shutdown operating on ultra low sulfur diesel fuel. The rule also requires periodic tune-ups for the EGU burner and combustion controls, which Morgantown is compliant.

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.

Auxiliary Boiler MACT

The auxiliary boilers are subject to the National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR part 63, Subpart DDDDD (Boiler MACT).

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_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.
Please Note: Potomac River Station is no longer in operation, shutdown October 2012.

MARCH 2008 – Opacity CONSENT DECREE

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 Chalk Point Generating Station. Requirements from this Consent Decree are discussed later in the fact sheet and have been incorporated into the State-Only Section of the Title V permit.

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 1 and 2) at Morgantown Generating Station. The NO_X reductions under the Healthy Air Act occurred in two phases, 2009 and 2012. GenOn installed pollution control equipment at Morgantown Generating Station in order to comply with Healthy Air Act requirements by reducing NO_X, SO_2 and mercury emissions.

On August 29, 2007, GenOn received a Certificate of Public Convenience and Necessity (CPCN) from the Public Service Commission (Case #9085) for the installation of a flue gas desulfurization (FGD) system and associated equipment to control sulfur dioxide (SO_2) and mercury air emissions. The FGD system became operational in December 2009.

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a market-based carbon dioxide (CO_2) cap and trade program designed to reduce CO_2 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 required Maryland to adopt regulations by December 31, 2008, implementing the RGGI program. The Maryland CO_2 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 CO_2 emissions from fossil fuel-fired electric generating units located in Maryland having a capacity of at least 25 megawatts;
2) Distribute CO_2 allowances to stakeholders through auction, sale and/or allocation;
3) Require each affected source to have a CO_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_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_2 emissions.
9) Require affected sources to submit an application for a CO_2 Budget Permit. A CO_2 Budget Permit when issued will be an attachment to the Part 70 permit.

GREENHOUSE GAS (GHG) EMISSIONS

Morgantown 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 GenOn Morgantown 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 2013 thru 2016, showed that GenOn Morgantown Generating Station is a major source (threshold: 100,000tpy CO_2e) for GHG's (see Table 3 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 Morgantown Generating Station based on its Annual Emission Certification Reports:

Table 3: Greenhouse Gases Emissions Summary

GHG	**Conversion factor**	**2013** tpy CO_2e	**2014** tpy CO_2e	**2015** tpy CO_2e	**2016** tpy CO_2e
Carbon dioxide CO_2	1	4,028,640.43	6,265,623.30	4,278,310.65	4,858,484.68
Methane CH_4	25	64.68	733.86	502.53	571.34
Nitrous Oxide N_2O	298	72.30	106.92	73.14	83.16
Total GHG CO_{2eq}		**4,028,777.41**	**6,266,464.07**	**4278886.32**	**4,859,139.20**

EMISSION UNIT IDENTIFICATION

Morgantown 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

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
F1	3-0002	Unit 1: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with a LNBs, SCR, ESP and FGD. The unit's exhaust is directed to an individual flue 400 foot stack. When the FGD system is not in service the Unit's exhaust is directed to a 700 foot by-pass stack. The Unit maintains the capability of firing No. 6 oil as an alternative primary fuel	June 1970 (Commercial operation date)
F2	3-0003	Unit 2: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with a LNBs, SCR, ESP and FGD. The unit's exhaust is directed to an individual flue 400 foot stack. When the FGD system is not in service the Unit's exhaust is directed to a 700 foot by-pass stack. The Unit maintains the capability of firing No. 6 oil as an alternative primary fuel	June 1971 (Commercial operation date)
F-CT 1	4-0068	General Electric Frame 5 combustion turbine rated at 20 MW and used for black start capability and peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	March 1970
F-CT 2	4-0069	General Electric Frame 5 combustion turbine rated at 20 MW and used for black	June 1971

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
		start capability and peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	
F-CT 3	4-0070	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-CT 4	4-0071	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-CT 5	4-0073	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-CT 6	4-0074	General Electric Frame 7 combustion turbine rated at 65 MW and used for peaking service. The combustion turbine is fired on No. 2 fuel oil. The exhaust gas is vented to a single 20 ft high stack.	June 1973
F-Aux 1	4-0015	Auxiliary boiler No. 1 manufactured by CE-Alstom (Model No.30 VP-12W) is used for start-up steam and space heat heating. Auxiliary boiler No. 1 is fired with No. 2 fuel oil and has a maximum rating of 164 mmBtu/hr.	1970
F-Aux 2	4-0191	Auxiliary boiler No. 2 manufactured by CE-Alstom (Model No.30VP21808R/48) is used for start-up steam and space heat heating. Auxiliary boiler No. 2 is fired with #2 fuel oil and has a maximum rating of 219.3 mmBtu/hr.	June 2004
F-Aux 3	4-0017	Auxiliary boiler No.3 manufactured by CE-Alstom (Model No.30 VP-12W) is used for start-up steam and space heat heating.	1970

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
		Auxiliary boiler No. 3 is fired with No. 2 fuel oil and has a maximum rating of 164 mmBtu/hr.	
F-Aux 4	4-0018	Auxiliary boiler No. 4 manufactured by CE-Alstom (Model No.30 VP-12W) is used for start-up steam and space heat heating. Auxiliary boiler No. 4 is fired with No. 2 fuel oil and has a maximum rating of 164 mmBtu/hr.	1970
Coal Barge Unloader	6-0138 (CPCN 9031)	The barge loading facility consists of a dock, barge unloader, a transfer and distribution system and a railcar loading facility. The barge unloader system is sized to unload up to 5.0 million tons of coal per year. The barge unloader's transfer and distribution system is integrated into Morgantown's existing coal handling system.	October 2007
Gypsum Barge Loading System	017-0014-6-0153 (CPCN 9148)	The Gypsum Barge Loading System is to convey and load gypsum produced by both the Chalk Point and Morgantown SO_2 FGD systems. The Gypsum Barge Loading System consists of the following subsystems: 1000-tph conveyor system; five transfer towers, one pier tripper conveyor, one telescoping barge load-out conveyor and rail unloading hopper and conveyor for chalk Point gypsum transfer.	October 2007
FGD System	(CPCN 9085)	A wet flue gas desulfurization (FGD) system is installed on both Units 1 and 2. The FGD system controls SO_2 and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing gypsum 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 three emergency diesel engines.	December 2009

Emissions Unit Number	MDE Registration Number	Emissions Unit Name and Description	Date of Installation
Coal Blending System	017-0014-6-0154 (CPCN 9148)	The coal blending system is designed to blend various coals with different characteristics to match the specification of the Morgantown's boilers and air quality control equipment. The coal blending system consists of the following subsystems: new stack-out facilities in the south coal yard; underground reclaim facilities in existing south and north coal yards; reclaim transfer point to integrate the reclaim from the north and south coal yards; refurbished and upgraded emergency reclaim; and enclosed transfer station with dust suppression system.	March 2010
STAR	6-0150 (CPCN 9229)	The STAR facility processes fly ash in to a Portland cement substitute. The STAR facility is made up of a 140 mmBtu/hr process reactor equipped with a supplemental 65 mmBtu/hr propane heater and a 20 mmBtu/hr propane duct burner. The unit is equipped with a fabric filter baghouse and wet flue gas desulfurization scrubber system. Exhaust gases are directed through a 125 foot stack. The STAR process facility includes a fly ash receiving feed silo and a truck unloading facility, a 30,000 ton product storage dome which includes a product silo with a truck loading facility. The reactor, the storage dome and silos are equipped with pneumatic ash transfer systems.	December 2011

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

Emission Units: F1 and F2: Boilers

F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with LNBs, SCR, ESP and FGD. The unit's exhaust is directed to an individual flue 400 foot stack equipped with two flow monitors and continuous emission monitors (CEMs) for PM, NO_X, SO_2, CO_2 and Hg. The Unit maintains the capability of firing No.6 oil as an alternative primary fuel. (**3-0002**)

F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. The boiler is a tangentially coal-fired supercritical unit with a superheater, single reheat and economizer. The Unit is equipped with LNBs, SCR, ESP and FGD. The unit's exhaust is directed to an individual flue 400 foot stack equipped with two flow monitors and continuous emission monitors (CEMs) for PM, NO_X, SO_2, CO_2 and Hg. The Unit maintains the capability of firing No.6 oil as an alternative primary fuel. (**3-0003**)

<u>By-pass Stack operation:</u>
There are several operating scenarios where the Morgantown 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, National Fire Protection Association (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.
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.

When venting through the by-pass stacks the exhaust gases do not pass through the FGD systems. Each 700 foot by-pass stack is equipped with two flow monitors, a continuous opacity monitor (COM). Compliance with the PM standard is demonstrated using stack testing, Compliance Assurance Monitoring (CAM) and the COMs on the by-pass stacks. Emissions of NO_X, SO_2, CO_2 and Hg from the by-pass stack are combined with the emissions from the units' FGD (normal operations) to demonstrate compliance with the HAA and all other applicable standards.

NSPS
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.

MACT
These boilers are subject to the requirements of 40 CFR Part 63 Subpart UUUUU-National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (F1 and F2). See Table IV-1e.

Compliance Status
On January 5-6, 2017, particulate matter stack test was performed on GenOn's Morgantown Unit #1 FGD system. Average unit load during runs of the test – 623 MW.

On January 4-5, 2017, particulate matter stack test was performed on GenOn's Morgantown Unit #2 FGD system. Average unit load during runs of the test – 627 MW.

Results are as follows:

	Results Unit #1	Standard	Results Unit 2	Standard
PM filterable	0.004 lb/MMBtu	0.100 lb/MMBtu per the March 2008 Consent Decree (State-Only) 0.14 lb/MMBtu	0.023lb/MMBtu	0.100 lb/MMBtu per the March 2008 Consent Decree (State-Only) 0.14 lb/MMBtu

	Results Unit #1	Standard	Results Unit 2	Standard
		(COMAR)		(COMAR)
PM filterable	0.004 lbs/MMBtu	0.03 lbs/MMBtu (30-day rolling EGU MATS)	0.023 lbs/MMBtu	0.03 lbs/MMBtu (30-day rolling EGU MATS)
PM Condensable	0.004 lb/MMBtu	None	0.004 lb/MMBtu	None
Total PM	0.008 lb/MMBtu	None	0.027 lb/MMBtu	None

In accordance with COMAR 26.11.27.05B, GenOn is required to submit an annual HAA report to MDE by March 1st of each year. The 2016 report was received by MDE electronically on February 27, 2017.

On June 12, 2017 the Department received GenOn Morgantown's May 2017 NO_X report (required by COMAR 26.11.38.04). The Permittee reported four (4) incidents in total for May when the 24-hour block average NO_X emission rate was greater than the target rate of 0.07 lbs/MMBtu (COMAR 26.11.38.04). The incidents were as follows: F1: Unit 1 – May 1st, 6th and 21st) and F2: Unit 2 – May 20th .The Permittee reported that three of the four incidents were the results of either starting up the unit at the end of the day and not having enough time to get the SCR controls up to operational temperatures before the averaging period ended or shutting down a unit at the very beginning of the averaging period and having to purge the SCR. One of the four incidents was the result of having an extended startup period before the SCR could reach the operational temperature due to an equipment malfunction.

The report includes the 2016 annual SO_2, NO_X, and Hg emissions as well as the 2016 ozone season NO_X emissions from each coal fired unit at GenOn's three generating stations (**Morgantown**, Dickerson and Chalk Point). The HAA annual and Ozone season NO_X emission limits became effective at the beginning of 2009 while the SO_2 & Hg emission limits became effective at the beginning of 2010. In 2012, the annual NO_X and Ozone season NO_X limits were reduced. Compliance with the HAA's NO_X and SO_2 limits are determined on a system-wide basis for GenOn.

GenOn reported 2016 annual system-wide NO_X emissions – 2,987.8 tons (limit 8,298 tons) – in compliance
GenOn reported 2016 ozone season system-wide NO_X emissions – 1,761.7tons (limit 3,567 tons) – in compliance
GenOn reported 2016 system-wide SO_2 emissions – 4,117.2 tons (limit 18,541 tons) – in compliance
Morgantown's Hg emissions- 3.7 lbs/yr (limit 66 lbs/yr) or 1.27 oz/tbtu (limit 14 oz/tbtu) – in compliance*

* The HAA Hg limit is a 12-month rolling limit. GenOn only reported their annual 12-month calendar Hg emissions. Since their annual calendar emissions for Hg is so far below the emission limit, it is assumed that all 12-month rolling periods will also be below

the emission limit. Monthly updates of 12-month rolling mercury emissions compliance can be found in the quarterly reports submitted to the Department.

Applicable Standards and Limitations:

A. Control of Visible Emissions

COMAR 26.11.09.05A (1) & (3) – Fuel Burning Equipment

"Areas I, II, V, and VI. In Areas I, II, V, and VI, 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 greater than 20 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

For the 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**]

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]**

In the event an FGD must be bypassed for any reason, the Permittee shall operate the opacity CEMS to record opacity for the duration of the bypass. In such event, compliance with applicable opacity limitations may be determined by opacity CEM data. **[Reference: COMAR 26.11.03.06C]**

The Permittee shall maintain all records necessary to comply with the data reporting requirements of COMAR 26.11.01.11E on file**. [Reference COMAR 26.11.01.11E]**

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(2)]**

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)]**

<u>For the Scrubber Stack</u>: The Permittee shall schedule monthly observations of visible emissions from the stack by a person trained to perform Method 9 observations and perform monthly Method 9 observation on the exhaust from the scrubber stack for a period of thirty (30) minutes.
Additional opacity monitoring requirements: To ensure compliance with the 20 percent opacity limit at higher particulate emission rates, the facility shall begin conducting Method 9 opacity observations whenever the 24-hour block average particulate emissions equal or exceed 0.03 lbs/MMBtu of heat input. The Method 9 opacity observations shall be conducted for 1-hour each day and continue until the 24-hour particulate block average is less than 0.03 lb/MMBtu heat input for the affected unit..
The Permittee shall keep records and report of the results (data) of the any opacity observations in the next required quarterly report**.** The Permittee shall also report CEM particulate matter data with the opacity observation data. **[Reference: COMAR 26.11.03.06C]**.

<u>Rationale</u>: <u>For the By-pass Stack</u>: The Permittee will operate a continuous opacity monitor. In 2008 GenOn and MDE signed a Consent Decree that established a PM limit of 0.100 lbs/mmBtu (State-Only); required GenOn to develop a CAM Plan early for the ESP stacks; required an Opacity Compliance Demonstration on the ESP stacks; and required PM CEMs on the future scrubbers.

From 2008 to 2009, GenOn was developing a CAM plan for the two Morgantown units. At that time, the units were controlled by ESPs. The CAM Plans compared 12 Particulate stack test runs to the opacity recorded during those runs to develop a curve. GenOn was able to vary the ESP voltage to reduce the control efficiency of the ESPs to get PM values greater than 0.100 lbs/mmbtu (State-Only) for unit #2 and values greater than 0.14 lbs/mmBtu for unit #1.

- Unit #1 (Y=0.005x-0.0119) (R^2=0.9429) Unit #2 (R^2=0.9404)
- Unit #1 (0.100 lbs/mmBtu ~ 22% opacity) Unit #2 (0.100 lbs/mmBtu ~ 20% opacity)
- Unit #1 (0.14 lbs/mmBtu ~ 30% opacity) Unit #2 (0.14 lbs/mmBtu ~ 27% opacity)
- 17 % and 18% opacity (90% of the 0.100 lbs/mmBtu was set as the CAM action number). One hour averages greater than these numbers required CAM actions

In 2010 GenOn installed and began operation of FGD scrubbers on the Morgantown Units. Due to the wet plumes, COMs could not be installed on the FGD scrubber stacks. The ESPs remain in operation on the units prior to the FGD scrubbers. The addition of FGD scrubbers reduces GenOn's particulate emissions by approximately 80%. Scrubbers must operate at a steady state condition (no throttling of FGD operations). Particulate CEMs were also installed. GenOn began submitting PM CEM data to MDE in quarterly reports (hourly and 24hr rolling data). All data submitted indicated compliance.
Both boiler flue stacks vent through a common stack, approximately 10 feet apart resulting in a combining steam plume when both units are in operation. From 2010 to 2011, GenOn used the FGD by-pass stacks (Old stacks with ESP but no scrubber) occasionally due to start-up and shutdown concerns. From 2012 to 2015, GenOn rarely needed to use the by-pass stacks. From 2015 to present, any use of the by-pass stack is a deviation of the MATs Rule. COMAR requires monthly visible emission observations of the scrubber stacks.

<u>For the Scrubber Stack</u>: The Permittee shall conduct EPA Method 9 observation for 30-minutes once per month. The Permittee also operate a PM CEMS on the scrubber stack. The data collected can be correlated with opacity. The Permittee has provided data that shows the PM emissions are an order of magnitude less that the PM limit and corresponding opacity readings are in range of 0% to 5% opacity.
Additional opacity monitoring requirements: Also EPA stated that at particulate matter emissions less than 0.03lb/MMBtu there would be little or no visible emissions. Visible emissions observations whenever the 24-hour block average particulate matter emissions equal or exceeds 0.03 lbs/MMBtu should ensure compliance with the opacity standard (20% VE standard) at higher particulate matter emissions rates.

B. Control of Particulate Matter Emissions

COMAR 26.11.09.06A(1) – Fuel-Burning Equipment Constructed Before January 17, 1972. "A person may not cause or permit particulate matter caused by the combustion of solid fuel or residual fuel oil in the fuel burning equipment erected before January 17, 1972, to be discharged into the atmosphere in excess of the amounts shown in Figure 1." (**Note**: Maximum allowable value in Figure 1 is 0.14 pounds/million Btu of heat input)

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."

40 CFR Part 63, Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units (MATS rule) - The Permittee will comply with a PM emissions limit of 0.03 pounds/million Btu of heat input. See the details in the compliance table for the MATS rule **Table IV – 1e – MACT Subpart UUUUU.**

Compliance Demonstration

For the By-pass Stack: The Permittee shall comply with the CAM Plan which includes monthly observations. **See Table IV-1b**.

For the Scrubber Stack: The Permittee shall operate and maintain a PM CEMS and perform an annual stack test in accordance with EPA Reference Methods. The Permittee shall submit a proposed test protocol to the Department for review and approval at least 30 days in advance of the first scheduled test date. Subsequent protocols shall be provided to the Department if the Permittee intends to make any material revisions to the previously submitted stack test protocols. The Permittee shall provide the Department with two weeks advance written notice of any scheduled stack test and shall submit the results of each stack test to the Department no later than 45 days following the stack test.

The Permittee may use the annual relative accuracy testing for the PM CEMS to satisfy the annual testing requirement. The Permittee shall operate and maintain a particulate matter continuous emissions monitoring system (PM CEMS). The Permittee shall maintain records of all particulate matter emissions tests and PM CEMS hourly data and submit a quarterly report of the PM CEMS data.
[Reference: COMAR 26.11.03.06C]

Rationale: The average 1-hour PM CEMS data will allow the Department to assess compliance with the 0.14 pounds/million Btu heat input. Upon operation of the FGD scrubber in 2009, the hourly average PM emissions reported in the quarterly PM CEMS reports have ranged from 0.002 to 0.022 pounds/million Btu heat input which is an order of magnitude less than the limit. This includes periods of boiler startup and shutdown.

C. Control of Sulfur Oxides

(1) **COMAR 26.11.09.07A(1)** - 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 I, II, V and VI:

(a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour;

(b) Residual fuel oils, 2.0 percent;

(c) Distillate fuel oils, 0.3 percent;

(d) Process gas used as fuel, 0.3 percent."

See additional requirements in Table IV-1e – CPCN 9085: FGD System.

Compliance Demonstration

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 NAAQS SO_2 standard, the Healthy Air Act limitations, the Acid Rain Program and the Cross-State Air Pollution Rule. **[Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, July 22, 1992, Consent Decree, Acid Rain Permit and 40 CFR Part 63 Subpart CCCCC**].

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 26.11.01.11E (2). **[Reference COMAR 26.11.01.11E(2)]**.

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 26.11.01.1E(2)(c)(i) through (vii). **[Reference: COMAR 26.11.01.11E(2)]**.

(1) Emission Limitation for Power Plants requirements*:*
COMAR 26.11.27.03C. SO$_2$ Emission Limitations.
(1) Except as provided in §E of this regulation, annual SO$_2$ emissions from each affected electric generating unit may not exceed the number of tons in §C(2) of this regulation.
(2) Annual Tonnage Limitations.

Affected Unit	Annual SO$_2$ Tonnage Limitations Beginning
	January 1, 2013
Morgantown Unit 1	4,678 tons
Morgantown Unit 2	4,646 tons
System-wide	18,541 tons

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 continuously monitor sulfur dioxide emissions 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 SO$_2$ standard, the Health Air Act limitations, the Acid Rain Program and the Cross-State Air Pollution Rule. **[Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, Acid Rain Permit and 40 CFR Part 63 Subpart CCCCC**].
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_X and SO_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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(2) 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.

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 Acid Rain account with the Environmental Protection Agency's Clean Air Markets Program at the end of each calendar year. GenOn Morgantown is given 16,962 allowances for Unit 1 and 16, 216 allowances for Unit 2 each year in the period 2010 and beyond. 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 two units. Although the Permittee is allowed to purchase allowances, the Acid Rain permit prohibits the Permittee from emitting sulfur dioxide emissions in excess of applicable SO_2 emissions standard. 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) & (2). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with SO_2 standard, the Health Air Act limitations, and the Acid Rain Program. **[Reference: COMAR 26.11.03.06C; COMAR 26.11.27.05A, and Acid Rain Permit**]. The Acid Rain Permit contain program specific recordkeeping requirements. **[Reference: 40 CFR Part 75, Subpart F].**

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(3) Cross-State Air Pollution Rule
TR SO_2 Group 1 - Trading Program 40 CFR Part 97 Subpart CCCCC
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635

Note: §97.606(c) SO_2 emissions requirements. For TR SO_2 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 SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 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 SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 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 requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633, the recordkeeping requirements found in §97.606, §97.630, and §97.634, and the reporting requirements; and the reporting requirements found in §97.606, §97.630, §97.633 and §97.634.

D. Control of Nitrogen Oxides
(1) NO_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_X emission rates in §C(2) of this regulation.
(2) The maximum NO_X emission rates as pounds of NO_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 input capacity of 250 Million Btu per hour or greater shall install, operate, calibrate, and maintain a certified NO_X CEM or an alternative NO_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_X emissions standards in this regulation using a CEM, compliance shall be determined as 30-day rolling averages."

Compliance Demonstration
NO_X RACT Requirements
The Permittee shall operate, calibrate, and maintain a certified NO_X CEM or an alternative NO_X monitoring method approved by the Department and the EPA on each installation. [**Reference: COMAR 26.11.09.08C(3)]**
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 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 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 26.11.01.11E(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_X Emission Limitations.
(1) Except as provided in §E of this regulation, annual NO_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.

Affected Unit	Annual NO_X Tonnage Limitations Beginning
	January 1, 2012
Morgantown Unit 1	2,094 tons
Morgantown Unit 2	2,079 tons
System-wide	8,298 tons

(3) Except as provided in §E of this regulation, ozone season NO_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.

Affected Unit	Ozone Season NO_X Tonnage Limitations Beginning
	May 1, 2012
Morgantown Unit 1	868 tons
Morgantown Unit 2	864 tons
System-wide	3,567 tons

(7) Electric System Reliability During Ozone Seasons.

(a) An exceedance of the NO_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_X emissions in excess of the emission limitation; and

(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_X allowances equivalent in number to the tons of NO_X emitted in excess of the emission limitation in §B(4) or (6), as applicable.

(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.

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_X and SO_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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(3) Control of NO_X Emissions from Coal-Fired Electric Generating Units
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_X Emission Control Requirements
A. Daily NO_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_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_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_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_X reduction requirements in COMAR 26.11.27.

C. Annual NO_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_X reduction requirements in COMAR 26.11.27.

<u>Compliance Demonstration</u>

COMAR 26.11.38.04 – <u>Compliance Demonstration Requirements</u>

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:

Affected Unit	24-Hour Block Average NO_X Emissions in lbs/MMBtu
Morgantown	
Unit 1	0.07
Unit 2	0.07

(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_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_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_X emission rates of this chapter.
(1) Compliance with the NO_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.

The Permittee shall maintain records sufficient to demonstrate compliance with requirements in COMAR 26.11.38. **[Reference: COMAR 26.11.03.06C]**

COMAR 26.11.38.06 – 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_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.

(4) 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. Morgantown Units 1 and Unit 2 are included in the GenOn System. See the details of the Potomac River Consent Decree in the Fact Sheet for Emission Units F-1 and F-2.

"Beginning May 1, 2007, GenOn shall not operate Morgantown Unit 1 unless it has installed and continuously operates, on a year-round basis, Selective Catalytic Reduction technology ("SCR") (or equivalent NO_X control technology approved pursuant to Paragraph 55) so as to achieve a 30-Day Rolling Average Emission Rate from such Unit not greater than 0.100 lb/mmBtu NO_X."
[Reference: Potomac River Consent Decree, Condition 53]
SCR was placed into operation on Unit 1 prior to May 2007.

"Beginning May 1, 2008, GenOn shall not operate Morgantown Unit 2 unless it has installed and continuously operates, on a year-round basis, SCR (or an equivalent NO_X control technology approved pursuant to Paragraph 55) so as to achieve a 30-Day Rolling Average Emission Rate from such Unit not greater than 0.100 lb/mmBTU NO_X." **[Reference: Potomac River Consent Decree, Condition 54]**

SCR was placed into operation on Unit 2 prior to May 2008.

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. 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]**

(5) 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. The renewal Phase II Acid Rain permit sets an annual average NO_X emissions limitation of 0.45 pounds NO_X per million BTU of heat input for Unit 1 & Unit 2. Excess emissions are tons of NO_X emissions in any calendar year that exceed the amount of NO_X calculated by multiplying 0.45 pounds of NO_X per million BTU of heat input for Unit 1 & Unit 2 times the total heat input during the year. At the end of each calendar year, the Permittee is penalized for any excess emissions.

(6) 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

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: **§97.406(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.

§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, record keeping and reporting requirements found in §97.406, §97.430, §97.431, §97.432, §97.433 and §97.434 for the NO_X Annual Trading Program and §97.506, §97.530, §97.531, §97.532, §97.533 and §97.534 for the NO_X Ozone Season Trading Program.

Emission Units: F1 and F2: Boilers Cont'd
F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**)
F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)

Potomac River Consent Decree
System-wide Annual Tonnage Limitations for NO_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_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. Paragraph 185, 188, and 189 refer to revise 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

Applicable Year	System-Wide Annual Tonnage Limitations for NO_x
2010 and each year after	16,000 tons

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_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. Paragraph 185, 188, and 189 refer to revise 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

Applicable Ozone Season	System-Wide Ozone Season Tonnage Limitations for NO_x
2010 and each ozone season thereafter	5,200 tons

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_X.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 59.]

4. If GenOn exceeds the limitations specified in Section IV, Subsection C (System-Wide Annual Tonnage Limitations for NO_X) or D (System-Wide Ozone Season Emissions Limitations), GenOn may not claim compliance with this Decree by using, tendering, or otherwise applying NO_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_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_X trading program set forth in the Maryland State Implementation Plan including, the Maryland NO_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_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_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_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_X emission limitations specifies 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_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_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_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_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.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 71]

9. In order to sell or transfer NO_x Allowances pursuant to Paragraph 63, GenOn must also timely report the generation of such NO_x Allowances in accordance with Section IX (Periodic Reporting) of this Consent Decree.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 64.]

10. For purpose of this Subsection, the "surrender of allowances" means permanently surrendering NO_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.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 65.]
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_X allowances equal to the amount by which the Ozone Season NO_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_X established in Paragraph 58 of the Consent Decree for the same year; and (2) the number of "annual" (non-ozone season) NO_X allowances equal to the amount by which the "annual" NO_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_X established in Paragraph 57 and the System Wide Ozone Season Tonnage Limitations for NO_X established in Paragraph 58 for that same year.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 66]

12. If any NO_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_X Allowances and a listing of the serial numbers of the transferred NO_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_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_X Allowances, GenOn shall include a statement that the third-party recipient(s) tendered the NO_X Allowances for permanent surrender to Plaintiffs in accordance with the provisions of Paragraph 68 within one (1) year after GenOn transferred the NO_X Allowances to them. GenOn shall not have complied with the NO_X Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred NO_X Allowances to Plaintiffs.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 67]

13. For all NO_X Allowances surrendered to Plaintiffs, GenOn or the non-profit third-party recipient(s) (as the case may be) shall first submit a NO_X Allowance transfer request form to EPA directing the transfer of such NO_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_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_X Allowances being surrendered.
[Reference: GenOn Potomac River Consent Decree, Section IV, paragraph 68]

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

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_X Emission Limitations, Section XX. Severing the Dickerson Plant: Revised System-wide NO_X Emission Limitations, XXI Severing the Morgantown and Dickerson Plants: Revised System-wide NO_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 requires 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]

<u>Compliance Demonstration</u>

<u>Monitoring, and Record Keeping and Reporting Requirements</u>

16. In determining Emission Rates for NO_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 NO_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 [NO_X, SO_2, 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): F1 and F2: Boilers Cont'd

COMPLIANCE ASSURANCE MONITORING (CAM) Plan for Morgantown Generating Station F1 (Unit 1) By-pass Stack only

Morgantown Unit 1 PM Emission Control

Table IV-1b		
COMPLIANCE ASSURANCE MONITORING (CAM) PLAN		
Electrostatic Precipitator (ESP) for UNIT 1 (Bypass Stack only)		
Applicable Requirement	**PM:** Emission limit: 0.14 pounds particulate matter per million Btu of heat input **Opacity**: 20 percent maximum	
	Indicator #1	Indicator #2
	Opacity at Stack	ESP Secondary Power
Measurement Approach	The stack continuous opacity monitor (COM) produces 1-minute average readings, which are then used to produce 6-minute averages and block 1-hour averages	The ESP total secondary power is calculated from voltmeters reading secondary voltage and ammeters reading secondary current. Block 1-hour averages are produced from 1-minute averages.

II. Indicator Range	The opacity indicator range is a block hourly average opacity of 17.0%. When the block hourly average opacity is over 19.0%, operators must look at the second CAM indicator, ESP total secondary power.	The total ESP secondary power indicator range is a block hourly average of 417 kW. Excursions below this indicator range trigger corrective actions and reporting requirements.
III. Performance Criteria		
1. Data Representativeness	The COM was installed on the stack per 40 CFR 60, Appendix B.	The voltmeters and ammeters are part of the ESP design and included in their instrumentation.
2. AQ/QC Practices and Criteria	QA/QC per 40 CFR 60, Appendix B	Voltmeters and ammeters and checked per standard PM schedule
3. Monitoring Frequency	Opacity is monitored continuously by the continuous opacity monitoring (COM) system.	Secondary power is monitored continuously by the plant information (Pi) system.
4. Record keeping	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.
5. (i) Reporting	Report the number, duration and cause of any excursion and the corrective action taken.	Report the number, duration and cause of any excursion and the corrective action taken.
(ii) Frequency	Quarterly	Quarterly

Morgantown Unit 1 is a base-load coal-fired steam-generating unit nominally rated at 640 MW. PM emission controls consist of cold side electrostatic precipitators (ESPs). Exhaust gases from the ESP exits through a single 700-ft-high stack.

Rationale for Selection of Performance Indicators
In an ESP, capture of particulate matter is obtained by having the flue gas flow pass through an electric field where the particulate matter is imparted with an electric charge. The electric fields are established by applying a direct current voltage across a pair of electrodes, a discharge electrode and a collection electrode. Ash particles become negatively charged and migrate towards the positively charged collection electrodes. Particulate matter is removed from the flue gas stream by magnetic attraction and retention on the collection electrode. Removal of the particulate matter falls by gravity into hoppers located below the ESP and is subsequently removed by the ash system and transported for off-site disposal.

The use of opacity data as an ESP performance indicator is a commonly used proxy for ESP performance. Generally, as opacity increases there is thought to be a causal effect of increased particulate emissions from the ESP. Although there may be other reasons for increasing opacity values, such as high flue gas velocities, re-entrainment problems, and particle size issues, there is typically a linear relationship between opacity, outlet loading, and ESP efficiency at normal operating conditions. During startup, shutdown or upset conditions, this relationship may not correlate as well. Despite this limitation, use of opacity is the preferred parameter as a CAM plan performance indicator. Opacity will be used as the primary ESP performance indicator.

Because the relationship between PM and opacity is not robust over all operating conditions, secondary ESP performance indicator will also be used. During the development of this CAM plan, particulate matter (PM) testing was conducted on the unit at varying ESP power levels in an effort to determine a reliable ESP performance indictor. The total secondary ESP power level was found to have a high correlation with PM emissions and was selected as the second CAM plan performance indicator. When the primary indicator (block 1-hr average opacity) is at or above 17%, secondary power levels of the total secondary power of the ESP will then be monitored.

In general, secondary ESP power can be a useful indicator of ESP performance. Typically, high secondary power to the ESP results in good ESP performance. In a properly operating ESP, secondary voltage tends to decrease from the inlet fields to the outlet fields, while the secondary current tends to increase. When the secondary voltage drops, due to grounded electrodes for example, less particulate is charged and collected. In addition, if the collection plates are not cleaned or rapped appropriately, the secondary current drops while the secondary voltage can remain high. Since the secondary power is the sum of the products of secondary voltage and current for each field, monitoring the use of secondary power levels will provide an additional measure of ESP performance.

Monitoring Approach

Two performance indicators will be used: ESP opacity as measured by the continuous opacity monitor (COM) in the exhaust will be used as the primary ESP performance indicator. Block 1-hour average opacity of 17% was determined to be the appropriate indictor range. Opacity values above the indictor range for this period will trigger the use of a second performance indicator – secondary power of the ESP. The indictor range for the total secondary power of the ESP is 417 KW in a block 1-hour average basis. Block hourly power levels below 417 kW will be considered an excursion of the CAM plan indicator. These events will be documented and reported to MDE on a quarterly basis.

The basis of the opacity, secondary power and PM emissions relationship used in developing the CAM plan were determined by the stack tests performed on Unit 1 in April 7 and 8, 2008.

CAM Plan for Morgantown Generating Station F2 (Unit 2) By-pass Stack only

Morgantown Unit 2 PM Emission Control

Table IV-1c		
COMPLIANCE ASSURANCE MONITORING (CAM) PLAN		
Electrostatic Precipitator (ESP) for UNIT 2 (Bypass Stack only)		
Applicable Requirement	**PM:** Emission limit: 0.14 pounds per million Btu of heat input **Opacity**: 20 percent maximum	
I. Indicator	Indicator #1	Indicator #2
	Opacity at Stack	ESP Third Field Secondary Power
Measurement Approach	The stack continuous opacity monitor (COM) produces 1-minute average readings, which are then used to produce 6-minute averages and block 1-hour averages	The ESP third field secondary power is calculated from voltmeters reading secondary voltage and ammeters reading secondary current. Block 1-hour averages are produced from 1-minute averages.
II. Indicator Range	The opacity indicator range is a block hourly average opacity of 18%. When the block hourly average opacity is over 18%, operators must look at the second CAM plan indicator, ESP third field secondary power	The ESP third field secondary power indicator range is a block hourly average of 92 kW. Excursions below this indicator range trigger corrective actions and reporting requirements.
III. Performance Criteria		
1. Data Representativeness	The COM was installed on the stack per 40 CFR 60, Appendix B	The voltmeters and ammeters are part of the ESP design and included in their instrumentation.
2. AQ/QC Practices and Criteria	QA/QC per 40 CFR 60, Appendix B	Voltmeters and ammeters are checked per standard PM schedule.
3. Monitoring Frequency	Opacity is monitored continuously by the continuous opacity monitoring system (COM).	Secondary power is monitored continuously by the plant information (Pi) system.

4. Record keeping	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.	Maintain for a period of at least five years records of inspections and of corrective action taken in response to excursions.
5. (i) Reporting	Report the number, duration and cause of any excursion and the corrective action taken.	Report the number, duration and cause of any excursion and the corrective action taken.
(ii) Frequency	Quarterly	Quarterly

Morgantown Unit 2 is a base-load coal-fired steam-generating unit nominally rated at 640 MW. For control of particulate emissions, the unit is equipped with the original cold sides ESPs consisting of two (2) parallel boxes (one for each ID fan train, labeled “A” side and “B” side). The ESP boxes are identical and each box is four (4) chambers wide and four (4) electrical fields deep.

Rationale for Selection of Performance Indicators
In an ESP, capture of particulate matter is achieved by having the flue gas flow pass through an electric field where the particulate matter is imparted with an electric charge. The electric fields are established by applying a direct current voltage across a pair of electrodes, a discharge electrode and a collection electrode. Ash particle become negatively charged and migrate towards the positively charged collection electrodes. Particulate matter is removed from the flue gas stream by magnetic attraction and retention on the collection electrode. Removal of the particulate from the collection plates is achieved by rapping of the plates wherein the particulate matter falls by gravity into hoppers located below the ESP, and is subsequently removed by the ash removal by the ash system and transported for off-site disposal.

The use of opacity data as an ESP performance indicator is a commonly used proxy for ESP performance. Generally, as opacity increases there is thought to be a causal effect of increased particulate emissions from the ESP. Although there may be other reasons for increasing opacity values, such as high flue gas velocities, re-entrainment problems, and particle size issues, there is typically a linear relationship between opacity, outlet loading, and ESP efficiency at normal operating conditions. During startup, shutdown or upset conditions, this relationship may not correlate as well. Despite this limitation, use of opacity is a preferred parameter as a CAM plan performance indicator. Opacity will be used as the primary ESP performance indicator.

Because the relationship between PM and opacity is not a robust overall operating condition, a secondary ESP performance indicator will be used. During the development of this CAM Plan, particulate matter (PM) testing was conducted on the unit at varying ESP power levels in an effort to determine a reliable second ESP performance indicator. The secondary power levels of the third ESP field were found to have a high correlation with PM emissions and were selected as the second CAM Plan performance indicator. When the primary indicator (block 1-hour average opacity) is at or above eighteen (18) percent, secondary power levels of the third field of the ESP will then be monitored.

In general, secondary ESP power can be a useful indicator of ESP performance. Typically, high secondary power to the ESP results in good ESP performance. In a properly operating ESP, secondary voltage tends to decrease from the inlet fields to the outlet fields, while the secondary current tends to increase. When the secondary voltage drops, due to grounded electrodes for example, less particulate is charged and collected. In addition, if the collection plates are not cleaned or rapped appropriately, the secondary current drops while the secondary voltage can remain high. Since the secondary power is the sum of the products of secondary voltage and current for each field, monitoring the use of secondary power levels will provide an additional measure of ESP performance.

<u>Rationale for Selection of Indicator Ranges</u>
Annual and CAM PM testing was performed on Unit 2 during July 2007. The results were used as the basis for determining the performance indicator range values.

A high linear regression correlation (R^2) of 0.9404 was calculated between the actual opacity and PM emission data. At the 20 percent opacity limit, the PM emissions are predicted to be about 0.095 lb/MMBtu which is slightly under the 0.100 lb/MMBtu presumptive limit proposed in the March 2008 Consent Decree. (*State-only Standard*)

An indicator range value for opacity is 18 percent on a block 1-hour average was selected. When the block 1-hour average opacity value is 18 percent or greater, the predicted PM emission level is approximately 0.085 lb/MMBtu, which provides approximately a 15 percent margin below the presumptive PM limit of 0.100 lb/MMBtu. (*State-only Standard*). An indicator range set 10 percent below the opacity limit of 20% is deemed to be sufficient margin to allow for corrective measures to be taken before the opacity limit is exceeded. If the opacity indicator is exceeded, the operators will turn to the second CAM plan indicator to diagnose and troubleshoot ESP performance.

<u>Monitoring Approach</u>
When the opacity levels of greater than 18 percent on a block 1-hour average are observed, secondary power levels for the third field shall be monitored. If the ESP third field secondary power levels are above the 92-kW indicator value, no

further action will be required. If secondary power levels below this level on a block hourly average basis, a response from operating and maintenance personnel will be triggered, at which time appropriate inspection and maintenance of the ESP and its auxiliary components (ash hopper levels, rapping, TR indicators, etc) will be performed. Operating periods where the block 1-hour average ESP third field secondary power level is below 92 kW will be considered an excursion of the CAM Plan indicator. Information on all CAM plan excursions including, the date, time, and duration of the excursion, along with corrective action taken, block 1-hour average opacity data, and block 1-hour average ESP third field secondary power data, will be reported to MDE in the quarterly reports.

Emissions Unit Number(s): FGD System for F1 and F2

A wet flue gas desulfurization (FGD) system is installed on both Units 1 and 2. The FGD system controls acid gases (SO_2 & HCl) and Hg. The FGD system uses limestone slurry with in-situ forced oxidation, producing gypsum 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 three (3) emergency diesel engines (two quench pump and one fire pump). **[CPCN: #9085]**

Compliance Status

In December 2009, GenOn commenced operation of the new FGD scrubber (CPCN # 9085) on the two coal fired boilers to comply with Maryland's HAA.
On April 26-30, 2010, the GenOn conducted NSPS Subpart OOO initial performance test visible emission observations on the Limestone Preparation & Gypsum Handling Systems at their Morgantown Generating Station as required by their CPCN No. 9085. The performance test report was received June 2, 2010. The test results show that all of the 33 emission points monitored (observed) are in compliance with the opacity standards found in 40 CFR 60 Subpart OOO and the Facility's CPCN No. 9085.

Applicable Standards and Limitations:
[Reference: CPCN #9085: II. Applicable Air Quality Regulations]
10. The Morgantown 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_2, NO_X and either O_2 or CO_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 51, Appendix P, §3.3-3.8 or §3.9 as incorporated by reference.
b) **COMAR 26.11.03.19**-Requires GenOn to notify MDE and EPA and at renewal to update the existing Morgantown Part 70 Operating Permit (No. 24-017-00014) to include applicable APC Project requirements. ***(Completed)***
c) **COMAR 26.11.06.02C(1)-**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 greater than 20 percent opacity.
d) **COMAR 26.11.06.03B(1)-**Prohibits GenOn from discharging into the outdoor atmosphere from any confined source (i.e., the limestone, gypsum and other material storage silos) particulate matter in excess of 0.05 grains per dry standard cubic feet (gr/dscf)(115 mg/dscm).
e) **COMAR 26.11.06.03C(1)-**Prohibits GenOn from causing or permitting emissions from an unconfined (fugitive) 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 Morgantown APC Project (limestone, gypsum, and sorbent to control sulfuric acid mist emissions), 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 26.11.09.05A(1)-**Prohibits GenOn from discharging emissions from fuel burning equipment, other than water in an uncombined form, which is greater than 20 percent opacity. Exceptions: limitations do not apply during times of load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment which are not greater than 40 percent opacity and do not occur for more than six consecutive minutes in any 60 minute period.

j) **COMAR 26.11.09.05E(2) and E(3)**-Prohibits the discharge of emissions from the quench pump engines, 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 two 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.

k) **COMAR 26.11.09.06A(1)**-Prohibits GenOn from causing or permitting particulate matter emissions from Morgantown Units 1 and 2 in excess of 0.14 lb/MMBtu. (Figure 1 of COMAR 26.11.09.06A). *[Compliance with the March 6, 2008 Consent Decree PM Emission limit 0.100 mmBtu/hr (State-only) indicates compliance with COMAR 26.11.09.06A]*

l) **COMAR 26.11.09.07A(1)(a)**-Prohibits GenOn from burning coal that would result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu actual heat input.

m) **COMAR 26.11.09.07A(1)(c)-**Prohibits GenOn from burning distillate fuel oil in the quench pumps with a sulfur content greater than 0.3 percent.

n) **COMAR 26.11.27**-Requires GenOn to comply with the applicable emissions limitations for NO_X, SO_2 and mercury as well as the monitoring and record keeping requirements contained in COMAR 26.11.27.

[Reference: CPCN #9085: III. New Source Performance Standard (NSPS) Requirements]

12. The equipment at Morgantown identified in [CPCN 9085] Table 1a, Table 1b and Table 1c 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 seven percent opacity.

13. Each of the three diesel engine-driven (two quench pumps and one fire pump) 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 #9085: IV. Operational Restrictions and Limitations]
14. GenOn shall:
a) Install, maintain and operate the new limestone, gypsum, sulfuric acid mist (SAM) control sorbent, and hydrated lime unloading, storage, transfer and distribution equipment and systems with associated particulate matter control methods listed in [CPCN 9085] Table 1a-c and Table 2 in accordance with original design criteria, vendor recommendations and best management practices, and in such a manner as to ensure full and continuous compliance with all applicable regulations.
b) Update Morgantown's Best Management Practices (BMP) Plan, as required by the facility's Part 70 Operating Permit (Permit No. 24-017-0014), to include the new limestone, gypsum, SAM control sorbent, and hydrated lime transfer storage and distribution equipment. The Plan shall document what reasonable precautions 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 that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and preventative maintenance 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 9085] Table 1a-c and Table 2, GenOn shall submit a request to ARA 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 9085] Table 1a-c and Table 2 of these conditions. GenOn shall be authorized to make the changes proposed in the written request unless ARA denies the request within 30 days of the receipt of the request.

[Reference: CPCN #9085: Miscellaneous]
86. Sulfuric acid mist emissions from Units 1 and 2 combined shall not exceed 1,194 tons per year (tpy) in any rolling 12-month cumulative period.
a. Mirant shall maintain records of monthly and 12-month rolling total emissions of SAM from Units 1 and 2 and submit to ARA semi-annually by July 30 for the period January 1 through June 30, and by January 30 for the period July 1 through 31 December;
b. At least 30 days prior to the anticipated date of start-up of the APC systems, Mirant shall provide MDE and the PSC with a plan outlining a methodology for determining SAM emissions from Units 1 and 2. Upon approval from ARA, Mirant shall implement the SAM emissions estimating protocol. ***(Completed)***

Compliance Demonstration
[Reference: CPCN #9085: V. Testing]
17. In accordance with COMAR 26.11.01.04A, GenOn may be required by ARA to conduct additional stack tests to determine compliance with COMAR Title 26, Subtitle 11. This testing will be done at a reasonable time.

[Reference: CPCN #9085: VI. Monitoring]
18. GenOn shall operate CEM systems for SO_2, NO_X and CO_2 or O_2, under 40 CFR part 75 and COM systems for Morgantown Unit 1 and 2.
The Permittee shall calculate the Unit's SAM emissions based on the empirical SAM formation relationship found in Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Revision 3 (Southern Company 2005), the SAM emission stack tests results required by the CPCN 9085 Condition 87 (40 CFR 60, Appendix A, Method 8), the actual unit heat input and the actual fuel sulfur content.
The Permittee use the following formula using the SAM stack test results adjusted by the average monthly fuel sulfur content and monthly heat input to calculate the monthly and 12 month rolling SAM emissions:
Monthly SAM Emissions (tons/month) = SAM Stack test Rate (lbs/mmBtu) x Coal Sulfur Adjustment Factor (average Monthly Coal Sulfur Content/Stack Test Coal Sulfur Content)/2000 lbs/ton

[Reference: Letter dated Dec 10, 2009 to MDE from Mirant Mid Atlantic LLC: Re: CPCN Case #9085, Condition 86b. – Method to Determine Sulfur Acid Mist Emissions from Morgantown Units 1 and 2]

[Reference: CPCN #9085: VII. Recordkeeping and Reporting]
24. All records and logs required by this CPCN shall be maintained at the facility for at least five years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of ARA.

20. GenOn shall submit to ARA 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. ***(Completed)***

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

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

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

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

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

Emissions Unit Number(s): F1 and F2 Boilers Cont'd
F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**)
F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)

MACT Subpart UUUUU

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.

<u>Compliance Status</u>
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.

<u>Please Note</u>: Letter dated March 25, 2015 from GenOn stated the following: "With the implementation of EPA's Mercury and Air Toxics Standards (MATS) rule in April, the option of operating units on the bypass stacks will be all but eliminated due its strict emission limits…." The Permittee will restrict the use of the bypass stack to situations where personnel safety or equipment preservation is involved. Under this limited operating scenario, it will not be possible to certify the CEMs on the bypass stack. The CEMS on the bypass stack is currently certified and will remain in operation until the certification expires. The bypass stack at Morgantown will not be monitored by certified CEMs or tested on a quarterly basis after the CEMS certification expires.

For **F1**: Unit 1: The initial performance tune-up was completed between March 14 and June 2, 2015. The initial performance tune-up is require to be performed prior to but no later than 54 months (48 months plus 180 days) from the compliance date of the Rule (April 16, 2015) if the unit employs neural network combustion controls. Unit #1 does employ neural network combustion controls.

For **F2**: Unit 2: The initial performance tune-up was completed between March 16, 2013 and May 11, 2013. The first tune-up is required as part of the MATS initial compliance demonstration and subsequent tune-ups are required every 48 calendar months if a neural network is employed. Morgantown is equipped with a neural network, but the timing of the subject and subsequent tune-ups was and will be dictated by the outage schedules and keeping the tune-ups synched with major outages.
The performance tune-up outage work was completed between March 19, 2016 and May 2, 2016. The post-outage combustion optimization was completed on June 23, 2016. Tune-ups are required on the unit every 48 calendar months since the unit employs neutral network combustion controls.

Letter dated December 19, 2016 from GenOn to EPA requesting PM CEMS Waiver Request – Alternate Temperature to the MATS Reference Method Requirements as noted in 40 CFR 63 Subpart UUUUU. On January 18, 2017, EPA granted approval of the temperature waiver. GenOn requested a MATS temperature waiver for the PM CEMs at GenOn's three Electrical Generating Stations (**Morgantown**, Dickerson, and Chalk Point) in Maryland. The temperature GenOn requested to use in certifying the PM CEMS is that of the EPA Method 5 (248 °F) and not the temperature found in the Utility

MATS. This alternate will align the PM CEMS used for the Utility MATS Rule with the particulate requirements of COMAR and EPA Method 5.

Applicable Standards and Limitations:

Control of HAPs Emissions

40 CFR Part 63, Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units.

§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 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 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. ***(Completed)***
(i) (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. ***(Completed & On-going)***
(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.** ***(Completed & On-going)***

(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. ***(Completed & On-going)***

(A) *Not Applicable*.

(B) *Not Applicable*

(d) *Not Applicable*.

"(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) *Not Applicable*.

(g) *Not Applicable*.

(h) *Not Applicable*.

(i) *Not Applicable*.

"(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." ***(Completed and On-going)***

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) *Not Applicable*.

(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 **SO_2 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 SO_2 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, CO_2, O_2, 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) *Not Applicable*.

(b) *Not Applicable*

(c) *Not Applicable*

(d) *Not Applicable*

(d)(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_2, HCl, or HF emissions limit in Table 1 or **2** to this subpart through use of an 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 CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO_2, 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_{hj} 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."***(Completed)***
"(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."
(g) *Not Applicable*
(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) *Not Applicable*.
(b) *Not Applicable*.

"(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) *Not Applicable*.
(g) *Not Applicable*.
(h) *Not Applicable*.
"(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to §63.10021(e).
(1) *Not Applicable*..
(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in §63.10021(e) must be no more than **48 calendar months** after the previous performance tune-up."

§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, **SO_2**, 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) *Not Applicable*.
(3) *Not Applicable*
(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 1.66×10^{-7};
(ii) Multiply HCl ppm by 9.43×10^{-8};
(iii) Multiply HF ppm by 5.18×10^{-8};
(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and
(v) Multiply Hg concentrations (µg/scm) by 6.24×10^{-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 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8}lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-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, <u>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</u>."
"(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_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_2 or CO_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_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_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_2 CEMS has a span value of 30 ppm or less.
(3) Calculate and record a 30-boiler operating day rolling average SO_2 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 SO_2 emission rates in the preceding 30 boiler operating days.
(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 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 SO_2 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 SO_2 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, 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 - <u>How do I demonstrate initial compliance with the emissions limits and work practice standards?</u>

(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. ***(Completed)***

(2) For a unit that uses a **CEMS to measure SO_2 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 SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart." ***(Completed)***

"(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to §63.10030(e). ***(Completed)***

(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. ***(Completed & On-going)***

(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."

<u>Continuous Compliance Requirements</u>
§63.10020 - <u>How do I monitor and collect data to demonstrate continuous compliance?</u>
"(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) *Not applicable*.

§63.10021 - <u>How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?</u>
"(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 , 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.

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n}\ (Eq. 8)$$

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.
(Completed & On-going)

(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_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_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_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_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_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_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_X and O_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_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 in hard copy, as specified in §63.10031(f)(5), through June 30, 2018. On or after July 1, 2018, report the date of all tune-ups electronically, in accordance with §63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed."

"(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.

(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) 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.

(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.
(2) *Not Applicable*.
(3) *Not Applicable*."
"(e) If you elect to average emissions consistent with §63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022.
(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 - <u>In what form and how long must I keep my records?</u>
"(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."

§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 (7), 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. **Note:** GenOn has selected Option 1.
(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;
(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 - <u>What reports must I submit and when?</u>
"(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. ***(Completed & On-going)***
(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 SO_2 CEMS. Use units of standard cubic meters per hour on a wet basis for flow rates.

(iv) *Not Applicable*.

(v) *Not Applicable*.

(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) *Not Applicable*.

(f)(1) On or after **July 1, 2018**, within 60 days after the date of completing each **CEMS (SO_2, 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.

(f)(2) On or after **July 1, 2018**, 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 the EPA's WebFIRE database by using the CEDRI that is accessed through the 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.

(f)(3) Reports for an **SO_2 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).

(f)(4) On or after July 1, 2018, 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 the EPA's WebFIRE database by using the CEDRI that is accessed through the 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.

(f)(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.

(f)(6) Prior to **July 1, 2018**, 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.
(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.”

<u>Emission Units: F-CT1 thru F-CT6: Combustion Turbines</u>

F-CT1 and F-CT2 – Two (2) General Electric Frame-5 combustion turbines each rated at 20 MW and used for black start capability and peaking service. These combustion turbines are fired on No. 2 fuel oil. The exhaust gas is vented to single 20 ft high stacks. **[4-0068 & 4-0069]**

F-CT3, F-CT4, F-CT5, F-CT6 – Four (4) General Electric Frame 7 combustion turbine each rated at 65 MW and used for peaking service. These combustion turbines are fired on No. 2 fuel oil. The exhaust gas is vented to single 20 ft high stacks. [**4-0070, 4-0071, 4-0073 & 4-0074]**

All combustion turbines were installed prior to subpart GG standards and therefore are not subject to 40 CFR Part 60, subpart GG and have no NO_X controls.

For CTs: <u>Control of Particulate Matter</u>: The requirements in Figure 1 and Figure 2 of this chapter do not apply to fuel-burning equipment burning gas or distillate oil. [COMAR 26.11.09.06A3(c)].

The CTs are <u>not</u> 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 before March 5, 2004.

<u>Compliance Status</u>
On August 8, 2012, testing was performed on two of the four (CT-3 thru CT-6) CTs as representative units since all four CTs are identical. The results while burning No. 2 fuel oil are as follows:

Unit	NO_X lb/MMBtu ISO corrected	Unit Load (MW)
CT-5	0.542	40
CT-6	0.518	39

The highest average base load NO_X emission rate – 0.542 lb/MMBtu
The highest average peak load NO_X emission rate – 0.623 lb/MMBtu*
* Per 40 CFR 75.19(c)(1)(iv)(C)(9), peak load is calculated by multiplying the base load by 1.15.

The heat input based capacity factors are as follows:

CTs	2016	2015	2014
CT 1	0.20%	0.23%	2.06%
CT 2	0.21%	0.35%	2.09%
CT 3	0.25%	0.27%	2.13%
CT 4	0.31%	0.33%	2.26%
CT 5	0.34%	0.25%	2.36%
CT 6	0.27%	0.32%	1.98%

Applicable Standards and limits

A. Control of Visible Emissions

COMAR 26.11.09.05A (1) & (3) – Fuel Burning Equipment

"Areas I, II, V, and VI. In Areas I, II, V, and VI, 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 greater than 20 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 visible emissions are less than 20 percent opacity. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period once every 168 hours of operation or at a minimum once per year.

The Permittee shall perform the following, if emissions are visible to human observer in excess of 20 percent opacity:

(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.

The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily when combustion turbine operating for 18 minutes until corrective action have reduce visible emissions to less than 20 percent opacity.

The Permittee shall keep a copy of the visible emissions readings and the certification of the visible emission reader(s) for at least five years on site and make available to the Department upon request. [**Reference: COMAR 26.11.03.06C**]

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".

B. Control of Sulfur Oxides

COMAR 26.11.09.07A(1) - 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 I, II, V and VI:

(a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour;
(b) Residual fuel oils, 2.0 percent;
(c) Distillate fuel oils, 0.3 percent;
(d) Process gas used as fuel, 0.3 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 **[Reference: COMAR 26.11.03.06C]**
The Permittee shall maintain records of fuel supplier's certification 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.

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."

(2) A person who owns or operates a combustion turbine with a capacity factor greater than 15 percent shall meet an hourly average NO_X emission rate of not more than 42 ppm when burning gas or 65 ppm when burning fuel oil (dry

volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive."

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. [**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].**

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.

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, §97.433 and §97.434 for the NO_X Annual Trading Program and §97.506, §97.530, §97.531, §97.532, §97.533 and §97.534 for the NO_X Ozone Season Trading Program.

Emission Units: F-Aux1, F-Aux 3, and F-Aux4: Auxiliary Boilers

F-Aux1, F-Aux 3, and F-Aux4 - Three (3) Auxiliary boilers, manufactured by CE-Alstom, used for start-up steam and space heating. Auxiliary boilers are fired with No.2 fuel oil and each have a maximum rating of 164 MMBtu/hr. **[4-0015, 4-0017 & 4-0018]**

These boilers are not subject to the requirements of 40 CFR Part 60 Subpart Db-Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units since these boilers were constructed prior to the June 19, 1984 applicability date

For Boilers: Control of Particulate Matter: The requirements in Figure 1 and Figure 2 of this chapter do not apply to fuel-burning equipment burning gas or distillate oil. [COMAR 26.11.09.06A3(c)].

Compliance Status:
The heat input based capacity factors are as follows:

Aux Boilers	2016	2015	2014
F-Aux1	Out of service	0.00%	0.00%
F-Aux3	Out of service	0.00%	0.00%
F-Aux4	1.81%	0.56%	0.00%

Applicable Standards and Limits:

A. Control of Visible Emissions

COMAR 26.11.09.05A (1) & (3) – Fuel Burning Equipment

"Areas I, II, V and VI. In Areas I, II, V and VI, 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 greater than 20 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 visible emissions are less than 20 percent opacity. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period semiannually.

The Permittee shall perform the following, if emissions are visible to human observer in excess of 20 percent opacity:

(a) inspect combustion control system and boiler operations,
(b) perform all necessary adjustments and/or repairs to the boiler 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 auxiliary boiler.

The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily for an 18 minute period until corrective action have reduce visible emissions to less than 20 percent opacity. **[Reference: COMAR 26.11.03.06C]**

The Permittee shall maintain records of all visible emissions observations. **[Reference: COMAR 26.11.03.06C]**

The Permittee shall report exceedance of 20 percent opacity in accordance with Permit Condition 4,Section III, Plant Wide Condition, "Report of Excess Emissions and Deviations" **[Reference: COMAR 26.11.03.06C]**

Rationale: The capacity factors for the aux boilers are less than 10 percent. The way the generating units are dispatched, the majority of the aux boilers operating time are at night which limits the opportunity at the time to perform visible emission observations. Therefore, semiannual observations are sufficient.

B. Control of Sulfur Oxides

COMAR 26.11.09.07A(1) - 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 I, II, V and VI:

(a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour;

(b) Residual fuel oils, 2.0 percent;

(c) Distillate fuel oils, 0.3 percent;

(d) Process gas used as fuel, 0.3 percent."

Compliance Demonstration

The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil complies with the limitation on sulfur content of the fuel oil. **[Reference: COMAR 26.11.03.06C].**

The Permittee shall retain annual fuel supplier certifications stating that the fuel oil is in compliance with this regulation must be maintained for at least 5 years. **[Reference: COMAR 26.11.09.07C].**

The Permittee shall report annual fuel supplier certification 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.

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) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request."

<u>Note</u>: COMAR 26.11.09.08B(5)(a) states that "for the purpose 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".

<u>Compliance Demonstration</u>
The Permittee shall perform a combustion analysis and optimize combustion at least once annually for any of the auxiliary boiler that operates more than 500 hours during a calendar year. [**Reference: COMAR 26.11.09.08G(1)(b)]**
If the auxiliary boiler operates more than 500 hours during a calendar year, the Permittee shall perform a combustion analysis and optimize combustion. **[Reference: COMAR 26.11.03.06C]**.
The Permittee shall maintain records of the results of the combustion analyses on site for at least five years and make them available to the Department and EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**. The Permittee shall maintain record of training program attendance for each operator on site for at least five years and make the records available to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) & COMAR 26.11.03.06C]**.
The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with support documentation in Annual Emissions certification Report. **[Reference: COMAR 26.11.03.06C].** The Permittee shall submit a list of trained operators to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) and COMAR 26.11.03.06C].**

COMAR 26.11.09.08K(3) – "A person subject to this regulation shall maintain annual fuel use records on site for not less than 3 years and make these records available to the Department upon request."

Emission Units: F-Aux2: Auxiliary Boilers Cont'd

F-Aux2 - Auxiliary boiler No. 2 manufactured by CE-Alstom (Model No.30VP21808R/48) is used for start-up steam and space heating. Auxiliary boiler No. 2 is fired with No.2 fuel oil and has a maximum rating of 219.3 mmBtu/hr. [**4-0191**]

The heat input based capacity factors are as follows:

Aux Boiler	2016	2015	2014
F-Aux2	8.42%	6.67%	3.40%

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
§60.40b - Applicability
(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

Applicable Standards/Limits:
A. Control of Visible Emissions
COMAR 26.11.09.05A (1) & (3) – Fuel Burning Equipment
"Areas I, II, V and VI. In Areas I, II, V and VI, 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 greater than 20 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 visible emissions are less than 20 percent opacity. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period semiannually.
The Permittee shall perform the following, if emissions are visible to human observer in excess of 20 percent opacity:
(a) inspect combustion control system and boiler operations,
(b) perform all necessary adjustments and/or repairs to the boiler 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 auxiliary boiler.

The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily for an 18 minute period until corrective action have reduce visible emissions to less than 20 percent opacity. **[Reference: COMAR 26.11.03.06C]**
The Permittee shall maintain records of all visible emissions observations. **[Reference: COMAR 26.11.03.06C]**
The Permittee shall report exceedance of 20 percent opacity in accordance with Permit Condition 4, Section III, Plant Wide Condition, “Report of Excess Emissions and Deviations”

Rationale: The capacity factor for the aux boilers are less than 10 percent. The way the generating unit is dispatched, the majority of the aux boiler operating time is at night which limits the opportunity at that time to perform visible emission observations. Therefore, semiannual observations are sufficient.

B. Control of Particulate Matter
§60.43b – Standard for particulate matter.
“(**f**) On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.”
“(**g**) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.”

§60.46b – Compliance and performance test methods and procedures for particulate matter and nitrogen oxides
“(a) The particulate matter emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction, and as specified in paragraphs (i) and (j) of this section. The nitrogen oxides emission standards under §60.44b apply at all times.”

Compliance Demonstration
§60.46b – Compliance and performance test methods and procedures for **particulate matter** and nitrogen oxides
“(b) Compliance with the particulate matter emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j).”
§60.48b - Emission monitoring for **particulate matter** and nitrogen oxides.

(j) Units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less **are not required to conduct PM emissions monitoring** if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

C. Control of Sulfur Oxides
COMAR 26.11.09.07A(1) - 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 I, II, V and VI:
(a) The combustion of all solid fuels on a premises where the sum total maximum rated heat input of all fuel burning equipment located on the premises is 100 million Btu (106 gigajoules) per hour or greater may not result in a total emission of oxides of sulfur in excess of 3.5 pounds per million Btu (1.50 kilograms per gigajoule) actual heat input per hour;
(b) Residual fuel oils, 2.0 percent;
(c) Distillate fuel oils, 0.3 percent;
(d) Process gas used as fuel, 0.3 percent."

Compliance Demonstration
The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil complies with the limitation on sulfur content of the fuel oil. **[Reference: COMAR 26.11.03.06C].**
The Permittee shall retain annual fuel supplier certifications stating that the fuel oil is in compliance with this regulation must be maintained for at least 5 years. **[Reference: COMAR 26.11.09.07C].**
The Permittee shall report annual fuel supplier certification to the Department upon request. **[Reference: COMAR 26.11.09.07C].**

§60.42b – Standard for sulfur dioxide.
"(**d**) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraph (d)(1), (2), or (3) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under this paragraph.
(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a Federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for

coal and oil of 30 percent (0.30) or less;
(2) Affected facilities located in a noncontinental area; or
(3) Affected facilities combusting coal or oil, alone or in combination with any other fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of he heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner."

Compliance Demonstration
§60.45b – Compliance and performance test methods and procedures for sulfur dioxide.
"(**a**) The sulfur dioxide emission standards under §60.42b apply at all times."
"(**j**) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described §60.49b(r)."
§60.47b – Emission monitoring for sulfur dioxide
"(**f**) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r)."
§60.49b – Reporting and recordkeeping requirements
"(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period."

D. 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) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request."

Note: COMAR 26.11.09.08B(5)(a) states that "for the purpose 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".

Compliance Demonstration
The Permittee shall perform a combustion analysis and optimize combustion at least once annually for any of the auxiliary boiler that operates more than 500 hours during a calendar year. [**Reference: COMAR 26.11.09.08G(1)(b)]**.
If the auxiliary boiler operates more than 500 hours during a calendar year, the Permittee shall perform a combustion analysis and optimize combustion. **[Reference: COMAR 26.11.03.06C]**.
The Permittee shall maintain records of the results of the combustion analyses and any stack tests on site for at least five years and make them available to the Department and EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**. The Permittee shall maintain record of training program attendance for each operator on site for at least five years and make the records available to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) & 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 26.11.03.06C].** The Permittee shall submit a list of trained operators to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) and COMAR 26.11.03.06C].**

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§60.44b – Standard for nitrogen oxides
"(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance test for any affected facilities that: (1) Combust, alone or in combination only natural gas, **distillate oil**, or residual oil with a nitrogen content of 0.30 weight percent or less; (2) Have a combined annual capacity factor of 10 percent or less for natural gas, **distillate oil**, and residual oil with a nitrogen content of 0.30 weight percent or less and (3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to

firing of natural gas, **distillate oil**, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, **distillate oil** and residual oil and a nitrogen content of 0.30 weight percent or less."

Compliance Demonstration
§60.46b – Compliance and performance test methods and procedures for particulate matter and **nitrogen oxides**
"(b) Compliance with the particulate matter emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j)."
§60.48b – Emission monitoring for particulate matter and **nitrogen oxides**.
(i)"The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a continuous monitoring system for measuring nitrogen oxides emissions."
§60.13(i) – "After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following: (2) Alternative monitoring requirements when the affected facility is infrequently operated."
§60.49b - Reporting and record keeping requirements.
(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.
(w) The reporting period for the reports required under this subpart is each 6-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

E. Operational Limit:
[Reference: CPCN Case #8949, Condition III – Operating Requirements]
(1) Operation of the auxiliary boiler shall not exceed 182,458 mmBtu in any consecutive 12-month period.

(2) Emissions from the auxiliary boiler shall not exceed the rates in the following table:

Pollutant	Maximum Short term rates (lb/mmBtu)*	Maximum Emission Rate (tons per year)
NO_X	0.30	27
SO_2	0.50	40
PM_{10}	0.10	15

* Emissions are in pounds per million Btu on a 24-hour average basis.

<u>Compliance Demonstration</u>

Compliance stack testing of the auxiliary boiler shall be conducted within 180 days of initial start-up to quantify pollutant emissions and demonstrate compliance with the emissions limits specified in Condition III.2 for the following air contaminants: nitrogen oxides ("NO_X") and particulate matter less than 10 microns in diameter ("PM_{10}"). [**Reference: CPCN Case #8949, Condition IV (1)]. (*Completed)*.**

At least 30 days prior to conducting any compliance stack test, the Permittee shall submit a test protocol to ARA for review. Compliance stack testing shall be conducted in accordance with ARA Technical Memorandum ("TM") 91-01, "Test Methods and Equipment Specifications for Stationary Sources" (January, 1991), as amended by Supplement 1 (1 July 1991), 40 CFR 51, 40 CFR 60, or subsequent test protocols approved by ARA. Test ports shall be located in accordance with TM 91-01 (January 1991), or subsequent or alternative measures approved by ARA. "). [**Reference: CPCN Case #8949, Condition IV (2)]** ***(Completed)***.

Testing shall be performed when operating at a minimum of 90 percent of the design load. If testing cannot be performed at the minimum load, then the actual load during testing shall become the allowable permitted load unless and until testing is performed while operating at a minimum of 90 percent of the design load. "). [**Reference: CPCN Case #8949, Condition IV (3)].** ***(Completed)***

In accordance with COMAR 26.11.01.04A, GenOn may be required to conduct additional stack tests at any time as may be prescribed by ARA. [**Reference: CPCN Case #8949, Condition IV (4)]**

Final results of each compliance stack test must be submitted to ARA within 60 days of completion of the test. Analytical data shall be submitted to ARA directly from the emission testing company. . [**Reference: CPCN Case #8949, Condition IV (5)]. *(Completed)*.**

The Permittee shall calculate the monthly mmBtu over the previous 12-month period for the auxiliary boiler to maintain compliance with the 182,458-mmBtu limit. **[Reference: COMAR 26.11.03.06C]**

The Permittee shall maintain records of the higher heating value of each shipment of fuel. **[Reference: CPCN Case #8949, Condition V (1)]**

§60.49b – Reporting and record keeping requirements.

"(**a**) The owner or operator of each affected facility shall submit notification of the date of initial startup as provided by §60.7." ***(Completed)***.

"(**d**) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month."

"(**f**) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity."

"(**h**) The owner or operator of any affected facility in any category listed in paragraphs (h) (1) or (2) of this section is required to submit excess emissions reports for any excess emissions which occurred during the reporting period."

"(**j**) The owner or operator of any affected facility subject to the sulfur dioxide standards under §60.42b shall submit reports."

"(**o**) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record."

"(**r**) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period."

"(**w**) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period."

Emissions Units : F-Aux1, F-Aux2 F-Aux 3, and F-Aux4: Auxiliary Boilers Cont'd

F-Aux1, F-Aux 3, and F-Aux4 - Three (3) Auxiliary boilers, manufactured by CE-Alstom, used for start-up steam and space heating. **[4-0015, 4-0017 & 4-0018]**

F-Aux2 - Auxiliary boiler No. 2 manufactured by CE-Alstom (Model No. 30VP21808R/48) is used for start-up steam and space heating. [**4-0191**]

The Permittee requested and was granted approval that the auxiliary boilers are defined as limited use boilers to comply with this MACT. Morgantown Generating Station will accept a 10% capacity factor restriction for F-Aux1, F-Aux3 and F-Aux4 boilers by incorporating this restriction in the Title V operating permit. (Per email dated July 11, 2013 – GenOn Morgantown Draft Title V Permit Fact Sheet Comments 7/11/2013)

F-Aux2 boiler has a 10% capacity factor restriction on its operation stated in CPCN Case No. 8949, Condition III – Operating Requirements.
See Operational Limits.

Compliance Status

On April 16, 2009, the Permittee submitted a Part 1 Application for the Industrial Boiler MACT Subpart DDDDD for the Auxiliary Boilers. On September 25, 2009, the Permittee submitted a Part 2 Application for the Industrial Boiler MACT Subpart DDDDD for the Auxiliary Boilers consisting of a case-by-case determination.

On August 20, 2012, the Department received the Permittee's initial notification.

The heat input based capacity factors are as follows:

Aux Boilers	2016	2015	2014
F-Aux1	Out of service	0.00%	0.00%
F-Aux2	8.42%	6.67%	3.40%
F-Aux3	Out of service	0.00%	0.00%
F-Aux4	1.81%	0.56%	0.00%

Applicable Standards and Limits:

Control of HAPs Emissions

40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

§63.7485 - Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

§63.7495 - When do I have to comply with this subpart?
"(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.
(b) If you have an **existing boiler** or process heater, you must comply with this subpart no later than **January 31, 2016**, except as provided in §63.6(i)."
"(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 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) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart."

§63.7500 - What emission limitations, work practice standards, and operating limits must I meet?
"(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart."
"(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart."

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards
As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or **a limited use boiler** or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.

Limited-use boiler *or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. [§63.7575]

General Compliance Requirements
§63.7505 - What are my general requirements for complying with this subpart?

"(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f)."

<u>Operational Limits</u>
[Reference: §63.12]
F-Aux1, F-Aux 3, and F-Aux4: Auxiliary Boilers 1, 3, & 4 operations shall be limited to an annual capacity factor of 10 percent or less or an annual heat input of not greater than 143,664 million Btu each.
F-Aux2: Auxiliary Boiler 2 operation shall be limited to an annual capacity factor of 10 percent or less or an annual heat input of not greater than 182,458 million Btu.
These units shall be defined as limit use boilers as defined in §63.7500(c) & §63.7575.

<u>Compliance Demonstration</u>
<u>Continuous Compliance Requirements</u>
§63.7540 - <u>How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?</u>
"(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section."
"(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575 or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.
(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;
(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity

for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;
(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;
(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the 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). Measurements may be taken using a portable CO analyzer; and
(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,
(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;
(B) A description of any corrective actions taken as a part of the tune-up; and
(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit."

"(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or **meets the definition of limited-use boiler or process heater in §63.7575**, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months."

"(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup."

§63.7555 - <u>What records must I keep?</u>
"(a) You must keep records according to paragraphs (a)(1) and (2) of this section.
(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 tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).”

§63.7560 - 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, or they must be accessible from on site (for example, through a computer network), 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.”
§63.7545 - What notifications must I submit and when?
“(a) You must submit to the Administrator 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 affected source before January 31, 2013, **you must submit an Initial Notification not later than 120 days after January 31, 2013. (*Completed*)**.
(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.
(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).”

§63.7550 - What reports must I submit and when?

“(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in §63.7495.

(2) The first compliance report must be postmarked or submitted 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 each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.
(5)(i) Company and Facility name and address.
(ii) Process unit information, emissions limitations, and operating parameter limitations.
(iii) Date of report and beginning and ending dates of the reporting period.
(iv) The total operating time during the reporting period.
(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.
(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.
(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.
(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of §63.7530, that demonstrates that your source is still

meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).
(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.
(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).
(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.
(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.
(xiii) If a malfunction occurred during the reporting period, the 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. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.
(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.
(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).
(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.
(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.
(1) A description of the deviation and which emission limit or operating limit from which you deviated.
(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.
(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.
(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).
(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).
(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.
(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).
(4) The date and time that each deviation started and stopped.
(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.
(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.
(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.
(8) A brief description of the source for which there was a deviation.
(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.
(f)-(g) [Reserved]
(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.
(1) Within 60 days after the date of completing each performance test (defined in §63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in §63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting

Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using 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 the 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 the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.
(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.
(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator."

Emissions Units: Coal Barge Unloader

The barge loading facility consists of a dock, barge unloader, a transfer and distribution system and a railcar loading facility. The barge unloader system is sized to unload up to 5.0 million tons of coal per year. The barge unloader's transfer and distribution system is integrated into Morgantown's existing coal handling system. (**6-0138, (CPCN #9031)**)

Compliance Status
On March 21 to 25, 2009 during the 1st barge unloading operation after reaching maximum capacity, visible emissions (VE) performance testing was conducted by Golder Associates. The VE test was conducted within 180-days from initial start-up of the barge unloading operation- in accordance with condition #14 of the CPCN. No VE greater than 2.08% opacity was observed, which is in compliance with the 20% opacity limit.

Applicable Standards and Limits:
A. Control of Visible Emissions
New Source Performance Standards (NSPS) 40 CFR 60 Subpart Y—Standards of Performance for Coal Preparation Plant (**40 CFR §60.250**) (and the associated notification and testing requirements of 40 CFR §60.7, §60.8 and §60.11) which requirements include: (a) GenOn shall not cause to be discharged into the atmosphere gases from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system being constructed or modified by the Barge Unloading project which exhibit 20 percent opacity or greater (under 40 CFR §60.252(c)). Specifically, equipment that makes up the modified facilities includes: (1) Mechanical barge unloader; (2) Four conveyor transfer points; (3) Transfer point to rail car loading station; (4) Railcar loading station; and (5) Breaker building.
(b) The opacity standards shall apply at all times except during periods of startup, shutdown, or malfunction;
(c) At all times, including during periods of startup, shutdown and malfunction, GenOn shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions.
[Reference: CPCN #9031, condition 10]

Compliance Demonstration
Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the coal barge unloading project, GenOn shall conduct performance tests in accordance with the methods in GenOn's ARA-approved Performance Test Plan and furnished ARA and EPA with a written report of the results of such performance test(s). **[Reference: CPCN #9031, condition 14]** ***(Completed)***
GenOn shall perform a monthly inspection of the coal unloading and handling operations to verify that the reasonable precautions (BMPs) in Condition 12 of the CPCN are being implemented. Visible emission or deviations identified during the inspections shall be promptly corrected. [**Reference: CPCN #9031, condition 15]**
GenOn shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the coal unloading and handling

facilities and any malfunction of its associated air pollution control equipment (40CFR 60.7(b). [**Reference: CPCN #9031, condition 18]**
Within 60 days of the initial startup date, GenOn shall provide ARA a Performance Test Plan that describes the proposed method for conducting the initial performance test that will demonstrate compliance with 40CFR 60.252 opacity standards for the affected facilities. The Test Plan shall comply with the requirements of §60.8 and §60.11, as they relate to performing opacity observations. [**Reference: CPCN #9031, condition 13]** ***(Completed)***

All notifications and reports required by 40 CFR 60 and Subpart Y, unless specified otherwise, shall be submitted to:

Regional Administrator
US Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

[**Reference: CPCN #9031, condition 22]**
GenOn shall furnish written notification to ARA and US EPA of the following events:

a) The date constructions is commenced postmarked no later than 30 days after such date; ***(Completed)***
b) The anticipated startup date, not more than 60 or less than 30 days prior to such date; ***(Completed)***
c) The actual date of initial startup postmarked with in 15 days after such date; ***(Completed)***
d) Notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applied postmarked 60 days or as soon as practicable before the change has commenced; and
e) The anticipated date for conducting the initial opacity observations (performance tests) postmarked not less than 30 days prior to such date. ***(Completed)***

[Reference: CPCN #9031, condition 19]

B. <u>Control of Particulate Matter</u>
COMAR 26.11.06.03D. - Particulate Matter from Materials Handling and Construction. 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 coal piles, unloading, transfer, and loading operation at GenOn's Coal Barge

Unloading Project, these reasonable precautions shall include, but not be limited to, the following when appropriate as determined by the control officer:
(1) Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces, which can create airborne dusts.
(2) Installation and use of hoods, fans, and dust collectors to enclose and vent the handling of dusty materials.
(3) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution
[Reference: CPCN #9031, condition 9c]

Compliance Demonstration
GenOn shall maintain and operate the following barge unloading equipment and its associated particulate matter control mechanisms with the potential to cause air pollution in accordance with original design criteria, vendor recommendations, and best management practices and in such a manner as to ensure full and continuous compliance with all applicable regulations:

Equipment	Control Mechanism
Barge Unloader	Telescoping Unloader
Conveyors	Covers or Enclosures
Transfer Towers	Enclosure
Railcar Transfer Point and Load out Station	Partial Enclosure

[**Reference: CPCN #9031, condition 12a]**

GenOn shall develop a coal handling best management practices (BMP) Plan for the coal barge unloader, associated conveyor system and railcar load out station to ensure that reasonable precautions will be used to prevent particulate matter from the coal barge unloading project equipment from becoming airborne. BMP's shall include, but are not limited to minimizing the area of permanent openings, using curtains at permanent openings, where feasible, and keeping doorways or other temporary openings closed when not in use. **[Reference: CPCN #9031, condition 12b]**
GenOn shall maintain the written reasonable precautions (BMPs) at the facility.
[**Reference: CPCN #9031, condition 16]**

GenOn shall keep written records of monthly inspections and maintenance performed under Condition 12 of the CPCN for the purposes of minimizing particulate matter emissions. Records shall include descriptions of the results of the inspection and maintenance, and any deviations and actions taken to address any noted deviations. [**Reference: CPCN #9031, condition 17]**

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 ARA. [**Reference: CPCN #9031, condition 20]**
Written records of monthly inspections and maintenance performed under Condition 12 of the CPCN for the purposes of minimizing particulate matter emissions shall be made available to the Department upon request. **[Reference: COMAR 26.11.06.06C**]

All air quality notifications and reports required by this CPCN shall be submitted to:

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

[Reference: CPCN #9031, condition 21]

Emissions Units: Coal Blending System & Gypsum Barge Unloading System

The coal blending system is designed to blend various coals with different characteristics to match the specification of the Morgantown's boilers and air quality control equipment. The coal blending system consists of the following subsystems: new stack-out facilities in the south coal yard; underground reclaim facilities in existing south and north coal yards; reclaim transfer point to integrate the reclaim from the north and south coal yards; refurbished and upgraded emergency reclaim; and enclosed transfer station with dust suppression system.**[(017-0014-6-0154), (CPCN #9148)]**

The Gypsum Barge Loading System is to convey and load gypsum produced by the Chalk Point, Dickerson and Morgantown SO_2 FGD systems. The Gypsum Barge Loading System consists of the following subsystems: 1000-tph conveyor system; five transfer towers, one pier tripper conveyor, one telescoping barge load-out conveyor and rail unloading hopper and conveyor for chalk Point gypsum transfer**.[(017-0014-6-0153), (CPCN #9148)]**

Compliance Status
GenOn commenced operation of the north yard of the coal blending facility (CPCN #9148) on April 27, 2010 and the south yard on December 17, 2010.
The BMP Plan and visible emission observation performance test plan were received on October 7, 2010.
The initial start-up date for the Gypsum Barge Loading system was December 30, 2009.

Applicable Standards and Limits:
Control of Particulate Matter
COMAR 26.11.06.03D. - Particulate Matter from Materials Handling and Construction. 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 activities associated with GenOn's Coal Blending/Gypsum Load out Project, 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.
(4) Covering, at all times when in motion, open-bodied vehicles transporting materials likely to create air pollution
[Reference: CPCN #9148, condition 11]

Compliance Demonstration
GenOn shall update Morgantown's Best Management Practices (BMP) Plan as required by the facility's Part 70 Operating Permit (Permit No. 24-017-00014), to include the equipment and material handling processes associated with the Project. The Plan shall document what reasonable precautions will be used to prevent particulate matter from project equipment and material handling processes from becoming airborne. The Plan shall include a description of the types and frequency of inspections and/or preventative maintenance that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and preventative maintenance have been conducted as proposed. MDE-ARA shall approve the BMP Plan prior to implementation. **[Reference: CPCN #9148, condition 14].** ***(Completed)***
GenOn shall maintain the written records of inspections, testing and monitoring results, and maintenance performed on Project emissions sources for the purposes of minimizing particulate matter emissions and demonstrating that coal blending/gypsum load out operations are meeting the approved BMP Plan. Records shall include description of the result of any inspection and maintenance. [**Reference: CPCN #9148, condition 15]**

All records and logs required by CPCN #9148 shall be maintained at the facility for at least five years after the completion of the calendar year in which they were collected. These data shall be readily available for inspection by representatives of MDE-ARA. [**Reference: CPCN #9148, condition 17]**

Written records of inspections and maintenance performed under Condition 14 of the CPCN for the purposes of minimizing particulate matter emissions shall be made available to the Department upon request. **[Reference: COMAR 26.11.06.06C**]

All air quality notifications and reports required by this CPCN shall be submitted to:

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

[Reference: CPCN #9148, condition 18]

Emissions Units: STAR

The STAR facility processes fly ash in to a Portland cement substitute. The STAR facility is made up of a 140 mmBtu/hr process reactor equipped with a supplemental 65 mmBtu/hr propane heater and a 20 mmBtu/hr propane duct burner. The unit is equipped with a fabric filter baghouse and wet flue gas desulfurization (FGD) scrubber system. Exhaust gases are directed through a 125 foot stack. The STAR process facility includes a fly ash receiving feed silo and a truck unloading facility, a 30,000 ton product storage dome which includes a product silo with a truck loading facility. The reactor, the storage dome and silos are equipped with pneumatic ash transfer systems. (**6-0150 (CPCN #9229)**)

Compliance Status

On January 4, 2012, GenOn commenced operation of the new fly ash processing facility (Staged Turbulent Air Reactor or STAR) (CPCN #9229) to comply with Maryland's Coal Combustion By-Products Regulation.

On January 17, 2017, GenOn performed a particulate matter, PM condensable, and mercury stack test on the STAR process. EPA Test Methods 30B was performed for mercury and EPA Method 5 and 202 were performed for particulate and PM condensable. During the test, the STAR process was feeding 40.26 tph of fly ash.

The results of the stack test were:

Particulate Matter-	0.0014 gr/dscf (standard – 0.05 gr/dscf) or 0.0048 lb/MMBtu
PM Condensable-	0.0065 gr/dscf or 0.0227 lbs/MMBtu (standard – none)
Mercury-	11.57E-06 lb/MMBtu or 0.652 ug/SCM (standard – none)
Visible Emissions-	<0.4% opacity (standard – 20%)

The results of the test show compliance with the particulate matter standard found under COMAR 26.11.06.03B and the opacity standard found under COMAR 26.11.06.02C.

On May 1, 2017 MDE received GenOn's 1st quarter 2017 STAR process CEM Report required by CPCN Case #9229. The report also shows that the STAR process is complying with the limits and requirements of the CPCN.
The results are as follows: NO_X, SO_2, and CO –

- No exceedances of their 12-month rolling PSD limits and no exceedance of their SO_2 500 ppm 24-hour block average limit.
- CEM down time was reported as follows: NO_X – 1.82%, SO_2 – 2.37%, and CO-1.46%
- Monthly and 12-month rolling Hg emissions were calculated using an MDE approved algorithm and reported in the quarterly report. For the 1st quarter 2017, the three (3) 12-month rolling calculated Hg emissions periods are: (12-month period ending: January – 0.0.0751 lbs, February – 0.0690 lbs, March – 0.0660 lbs. The 12-month rolling Hg limit (per the CPCN #9229) is 5 lbs Hg/12-month rolling period. The STAR facility is in compliance with the Hg limit.

Applicable Standards and Limits:
[Reference: CPCN 9229 – Emissions and Operational Requirements]
A. Control of Visible Emissions
A-7(c) *Visible Emission from General Sources.* – Prohibits GenOn from causing or permitting the discharge of emissions from any installation or building, other than water in an uncombined form, which is greater than 20 percent opacity [COMAR 26.11.06.02C].

Compliance Demonstration
The Permittee shall conduct visible emission observations using EPA Method 9 during the annual stack testing of stationary sources**. [Reference: CPCN #9229, condition A-16(c)]**
The Permittee shall visually inspect the exhaust gases from baghouse for visible emissions once a month for an 18-minute period and shall record the results of each observation. If visible emissions are observed, the Permittee shall perform the following:
(a) Inspect all process and/or control equipment that may affect visible emissions;
(b) Perform all necessary repairs and/or adjustments to all processes and/or control equipment within 48 hours so that visible emissions in the exhaust gases are eliminated;
(c) Document in writing the results if the inspections and the repairs and/or adjustments made to the processes and/or control equipment; and
(d) If visible emissions have not been eliminated within 48 hours, the Permittee shall perform a Method 9 observation once daily for an 18-minute period until the opacity standard of 20 percent is achieved.
[**Reference: COMAR 26.11.03.06C**].

The Permittee shall maintain on site for at least five (5) years records of the visible emission observations completed during the annual stack testing of the stationary sources. **[Reference: CPCN #9229 condition A-31]**
The Permittee shall submit to the Department within 60 days after completion of the stack test the results of the visible emission observations taken during the annual stack testing of the stationary sources. **[Reference: CPCN #9229 condition A-26]**

B. Control of Particulate Matter Emissions
A-7(d) *Particulate Matter from Confined Sources*. – Prohibits GenOn from causing or permitting the discharge into the outdoor atmosphere from any confined source of particulate matter in excess of 0.05 grains per dry standard cubic feet (gr/dscf) or 114 milligrams per dry standard cubic meter (mg/dscm) [COMAR 26.11.06.03B].

A-7(e) *Particulate Matter from Unconfined Sources*. – Prohibits GenOn from causing or permitting the discharge of emissions from an unconfined source without taking reasonable precautions to prevent particulate matter from becoming airborne [COMAR 26.11.06.03C].

A-7(f) *Particulate Matter from Materials Handling and Construction*. – 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 Morgantown STAR Facility, 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 [COMAR 26.11.06.03D].

Compliance Demonstration
From Confined Source: The Permittee shall perform annual stack testing to demonstrate compliance with PM emission limit in the exhaust gases of the stack of the stationary sources. **[Reference: COMAR 26.11.03.06C]**

From Unconfined Source: **[Reference: CPCN #9229 – Best Management Practice Requirements]**
A-33. GenOn shall update Morgantown's Best Management Practices (BMP) Plan as required by the facility's Part 70 Operating Permit (Permit No. 24-017-00014), to include the STAR Facility ash beneficiation process and associated control equipment and material handling processes associated with the project. The Plan shall document what reasonable precautions will be used to prevent PM from project equipment and material handling processes from becoming airborne. The Plan shall include a description of the types and frequency of inspections and/or preventative maintenance that will be conducted. In addition, GenOn shall define the associated records that will be maintained to document that inspections and preventative maintenance have been conducted as proposed. MDE-ARA shall approve the BMP Plan prior to implementation [COMAR 26.11.02.02H]. *Completed.*
The Permittee shall maintain records of the annual stack testing results on site for at least 5 years and make available to the Department upon request.
[Reference: COMAR 26.11.03.06C].
[Reference: CPCN #9229 – Best Management Practice Requirements]
A-34. GenOn shall keep written records of inspections, testing and monitoring results and maintenance performed on the Morgantown STAR Facility emissions sources for the purpose of minimizing PM emissions and demonstrating that the project operations are meeting the approved BMP Plan. Records shall include descriptions of the result of any inspection and maintenance [COMAR 26.11.02.02H].
The Permittee shall make available to the Department upon request records of the result of any inspection and maintenance activity performed. **[Reference: COMAR 26.11.03.06C]**

C. Control of Sulfur Oxides Emissions
A-7(g) *Sulfur Dioxide Emissions from General Sources*. – Prohibits GenOn from causing or permitting the discharge of emissions in the atmosphere gases containing more than 500 ppm of SO_2 during any 24-hour block average of hourly arithmetic CEMS concentrations [COMAR 26.11.06.05B(1)]

A-7(h) *Sulfuric Acid Emissions from General Sources*. - Prohibits GenOn from causing or permitting the discharge of emissions in the atmosphere gases containing sulfuric acid, sulfur trioxide, or any combination of them greater than 35 milligrams per cubic meter of emissions of gases reported as sulfuric acid [COMAR 26.11.06.05B(2)]

Compliance Demonstration
See Operational Limits

D. <u>Control of VOC Emissions</u>
A-7(i) *VOC Emissions from General Sources*. – Prohibits GenOn from causing or permitting the discharge of VOC emissions from any installation in excess of 20 lb/day unless the discharge is reduced by 85 percent or more overall [COMAR 26.11.06.06B(2)(c)].

Compliance Demonstration
See Best Management Plan Requirements listed under Control of Particulate Emissions

<u>Operational Limits</u>
A-8. Annual emissions from the Morgantown STAR Facility shall be less than the following in any consecutive 12-month period, rolling monthly, inclusive of emissions during periods of startup, shutdown and malfunction:

Pollutant	**Emissions Limit for Entire Morgantown STAR Facility (Tons per year)**
Sulfur Dioxide (SO_2)	40
Nitrogen Oxides (NO_X)	25
Carbon Monoxide (CO)	100
SO_2 or NO_X as a Particulate Matter less than 2.5 microns ($PM_{2.5}$) precursor	40

These federally enforceable limits are necessary for the Morgantown STAR Facility project to avoid triggering major modification requirements under Nonattainment New Source Review (NA-NSR) and Prevention of Significant Deterioration (PSD).

A-9. GenOn shall install, maintain, and operate the Morgantown STAR Facility equipment inclusive of the fabric filter baghouse and wet FGD scrubber system air pollution control technologies, in accordance with the original design criteria, vendor recommendations and best management practices, and in such a manner to ensure full and continuous compliance with all applicable requirements. The baghouse and wet FGD scrubber shall be in place and operational whenever the STAR process reactor is running [COMAR 26.11.02.02H].

A-10. GenOn is only permitted to process fly ash at the STAR Facility obtained from Morgantown, Chalk Point, and Dickerson Generating Stations [COMAR 26.11.02.02H].

A-11. The Morgantown STAR Facility shall not exceed an annual throughput of 360,000 tons of fly ash in any consecutive 12-month period, rolling monthly [COMAR 26.11.02.02H].

A-12. GenOn is only permitted to use propane as an auxiliary fuel [COMAR 26.11.02.02H].

Compliance Demonstration
[Reference: CPCN #9229 – Testing and Monitoring Requirements]
A-13. To demonstrate continuous compliance with the federally enforceable emissions limits set forth in Condition A-8, GenOn shall install, maintain, and operate a continuous emissions monitoring system (CEMS) for SO_2, NO_X, CO and CO_2 or O_2 for emissions from the STAR process reactor through the exhaust stack in accordance with a CEMS Monitoring Plan approved by MDE-ARA [COMAR 26.11.02.02H].
A-14. In accordance with operation of the CEMS, the Morgantown STAR Facility is subject to the following requirements:

a) Except as otherwise approved by the MDE-ARA, if GenOn is unable to obtain emissions data from CEMS because of a malfunction of the CEMS for more than 2 hours in duration, GenOn shall use the alternative measurement method approved by MDE-ARA;
b) The CEMS shall meet the quality assurance criteria of 40 CFR Part 60, Appendix F, as amended, which is incorporated by reference, or if applicable, the quality assurance criteria of 40 CFR 75, Appendix B, as amended;
c) Mass emission rates of NO_X, SO_2 and CO in pounds per hour (lb/hr), and heat input in million Btu per hour (MMBtu/hr) or million Btu per day (MMBtu/day) shall be calculated using the equations and emissions factors presented in 40 CFR Part 75, Appendix F;
d) As part of the emission calculation determination using 40 CFR Part 75, Appendix F, GenOn shall obtain a site-specific F-factor (representing a ratio of volume of dry flue gases generated to the calorific value of the fuel combusted or a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted). The site-specific F-factor shall be determined annually in accordance with the methodology on 40 CFR Part 75, Appendix F.
e) The CEMS shall record not less than four equally spaced data points per hour and automatically reduce data in terms of averaging times consistent with the applicable emission standard; and
f) The use of CEMS for enforcement purposes shall be as specified in MDE-ARA's Technical Memorandum 90-01 "Continuous Emissions Monitoring (CEMS) Policies and Procedures," which is incorporated by reference [COMAR 26.11.02.02H]

A-18. GenOn shall maintain a log of maintenance performed on the STAR process baghouse and wet FGD scrubber. The log of maintenance performed shall include record of dates, a description of the maintenance activity performed, a description of the reason for the maintenance activity (e.g. specific failure, routine) and other corrective actions taken to bring the control equipment into proper operation, if necessary. GenOn shall make maintenance records available to MDE-ARA upon request [COMAR 26.11.02.02H]

A-19. GenOn shall maintain a record of the STAR Facility fly ash and propane gas monthly throughput and annual throughput based on consecutive 12-month period, rolling monthly. GenOn shall make such records available to MDE-ARA upon request. Fly ash throughput records shall indicate the original source and date of receipt of the fly ash [COMAR 26.11.02.02H].

A-20. GenOn shall maintain fuel usage, pollutant concentrations, volumetric flow rates, and any other records necessary to determine the STAR Facility SO_2, NO_X, and CO actual emissions. Emission shall be calculated monthly and annually based on a consecutive 12-month period, rolling monthly for comparison with the annual emission limits in Condition A-8 [COMAR 26.11.02.02H].

A-21. GenOn shall maintain on file the following information related to the CEMS and make such records available to MDE-ARA upon request:

(a) CEMS or monitoring device performance testing measurements, including but not limited to volumetric flow rates, concentrations, and fuel emissions factors;
(b) CEMS performance evaluations and data accuracy audit reports;
(c) CEMS calibration checks;
(d) Adjustments and maintenance performed on the CEMS;
(e) Fuel sampling records required for CEMS calculations; and
(f) All other data relevant to maintaining compliance with the emissions limits [COMAR 26.11.02.02H]

A-27. GenOn shall submit a quarterly monitoring report to MDE-ARA, postmarked by the 30th day following the end of each calendar quarter that includes the following information for the STAR Facility:

(a) All instances of deviations from permit requirements;
(b) Separately the date, time and duration of each startup, shutdown and malfunction that occurred at the STAR Facility including, but not limited to the ash beneficiation process and associated air pollution control systems. The report shall include total monthly and consecutive 12-month total hours of startup, shutdown and malfunction of the STAR Facility equipment;
(c) The downtime or malfunction of the CEMS equipment. The report shall include the date and time of each period during which the CEMS was inoperative and the nature of monitoring system repairs or adjustments completed;
(d) The STAR Facility monthly hours of operations and annual hours of operation based on a consecutive 12-month period, rolling monthly;
(e) The propane gas monthly usage and annual usage based on a consecutive 12-month period, rolling monthly; and
(f) The annual emissions of SO_2, NO_X and CO for the STAR Facility based on a consecutive 12-motnh period, rolling monthly. An algorithm, including example calculations and emission factors, explaining the method used to determine emission rates shall be included in the initial quarterly monitoring report. Subsequent submittals of the algorithm and sample calculations are only required if GenOn changes the method of calculating emissions or changes emissions factors, or if requested by MDE-ARA [COMAR 26.11.02.02H].

A-28. GenOn shall comply with the following conditions for occurrences of excess emission and deviations from the requirements of this permit:
(a) Report any deviation from permit requirements that could endanger human health or environment, by orally notifying MDE-ARA immediately upon discovery of deviation [COMAR 26.11.01.07C].
(b) Promptly report occurrences of excess emissions, inclusive of periods of start-up and shutdown, expected to last for one hour or longer by orally notifying MDE-ARA of the onset and termination of the occurrences [COMAR 26.11.01.07C(1)]
(c) When requested by MDE-ARA, GenOn shall report all deviations from permit conditions, including those attributable 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 MDE-ARA. The written report must include the cause, dates and times of the onset and termination of the deviation, as well as the action planned or taken to reduce, eliminate and prevent the recurrence of the deviation [COMAR 26.11.02.02H]
(d) When requested by MDE-ARA, GenOn shall submit a written report to MDE-ARA within 10 days of receiving the request concerning an occurrence of excess emissions. The report shall contain the information required in COMAR 26.11.01.7C(2) [COMAR 26.11.01.07D(1)].
A-30. GenOn shall monitor and report actual greenhouse gas (GHG) emissions in accordance with 40 CFR Part 98. Reporting is required to begin for actual GHG emissions that are generated in the calendar year in which the facility begins operation, with the report submitted electronically to EPA by 31 March of the following year and annually thereafter [40 CFR Part 98].
A-31. All records and logs required by this CPCN shall be maintained by GenOn at the Morgantown STAR 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 MDE-ARA.
A-32. All air quality notifications and reports required by this CPCN shall be submitted to [COMAR 26.11.01.05]:

Program Manager
Air Quality Compliance Program
Maryland Department of the Environment
1800 Washington Boulevard, Suite 715
Baltimore, Maryland 21230

COMPLIANCE SCHEDULE

Morgantown Generating Station is currently in compliance with all applicable air quality regulations.

TITLE IV – ACID RAIN

Morgantown 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

The Permittee shall comply with the standards for recycling and emission reductions pursuant to 40 CFR Part 82, Subpart F.

SECTION 112(r) – ACCIDENTAL RELEASE

Morgantown Generating Station is not subject to the requirements of Section 112 (r) of the Clean Air Act.

PERMIT SHIELD

The Morgantown 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.

(2) No. __3__ 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.

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

(4) __✓__ 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;

(5) Containers, reservoirs, or tanks used exclusively for:

(a) ✓ Storage of butane, propane, or liquefied petroleum, or natural gas;

(b) No. 15 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;

(6) ✓ 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;

(7) ✓ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

(8) ✓ Potable water treatment equipment, not including air stripping equipment;

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

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

(11) ✓ Laboratory fume hoods and vents;

STATE ONLY ENFORCEABLE REQUIREMENTS

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

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."

Emissions Unit Number(s): F1 and F2: Boilers Cont'd **For By-Pass Stack:** **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)
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 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.”

March 2008 Opacity Consent Decree
Emissions Unit Number(s): F1 and F2: Boilers Cont'd **March 2008 Opacity Consent Decree** **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**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 11, 12, 13, 14, 15, 16, 17, 18.** ***PM limit is 0.100 pounds per million Btu of heat input by stack test and 0.100 pounds per million Btu of heat input 24-hour rolling average by PEM. (Condition 32 and 40, March 2008 Consent Decree)*** **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.*** *Completed:* **Consent Decree Section X. Installation of Particulate Matter CEMS, paragraph 31.** Each PM CEMS shall be comprised of a continuous particle mass monitor or equivalent device measuring particulate matter concentration for Morgantown Units 1 and 2 in lbs/mm Btu on a 24-hour rolling average basis. GenOn shall maintain, in an electronic database, the hourly average emission values recorded by all PM CEMS for five (5) years. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 32.]** 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 VIII. Particulate Matter Stack Testing, paragraph 33.]**

March 2008 Opacity Consent Decree
***(Completed)*:** **Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 34.** 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 VIII. Particulate Matter Stack Testing, paragraph 35]** GenOn shall submit quarterly PM CEMS reports to the Department that comply with COMAR 26.11.01.11E(2)(c)(i) through (vi). All data shall be reported in 24-hour rolling averages. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 36]** Not Applicable. **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 37]** ***(Completed)*:** **[Reference: Consent Decree Section VIII. Particulate Matter Stack Testing, paragraph 38]** 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 VIII. Particulate Matter Stack Testing, paragraph 39]**

March 2008 Opacity Consent Decree
Morgantown Units 1 and 2 shall be subject to a particulate matter emission limitation of **0.100 lbs/mmBtu heat input**. Compliance with the particulate matter limitation shall be demonstrated by stack test performed in accordance with Paragraphs 26 and 27, and by PM CEMs data in accordance with Section X, except that violations of the particulate matter emission limitation recorded by PM CEMs data shall be subject to §2-611 of the Environmental Article (Plan for Compliance). Violations of the particulate matter standard demonstrated by stack testing are not subject to a Plan for Compliance pursuant to §2-611 of the Environment Article and shall be subject to all sanctions and remedies available to the Department. **[Reference: Consent Decree Section XI. Particulate Matter Limitation Applicable to Morgantown Units 1 and 2, paragraph 40]** Not Applicable. **[Reference: Consent Decree Section XI. Particulate Matter Limitation Applicable to Morgantown Units 1 and 2, paragraph 41 & 42]** <u>Control of Sulfur Emissions</u> GenOn shall ensure that each train of coal scheduled for delivery to the Morgantown Plant for combustion in Units 1 and 2 is sampled for sulfur content prior to delivery. GenOn shall not burn coal that will cause SO_2 emissions in excess of 3.5 lbs/mm Btu heat input. [**Reference: Consent Decree Section III. Coal Sampling, paragraph 5]** <u>Truck Washing Facility</u> GenOn shall commence operation of a Truck Washing Facility designed to reduce fugitive particulate matter emissions at the Morgantown Plant no later than September 30, 2008. Each Truck Washing Facility shall be installed to wash the wheels, undercarriage, and sides of all trucks used to haul fly ash and bottom ash to off-site storage facilities. Each Truck Washing Facility shall consist of a steel basin with ramps on either end, or an array of nozzles that spray high velocity jets of water on the bottom and sides of trucks as they are driven through the device. Water shall be recirculated through a filtration tank. Accumulated ash solids in each filtration tank shall be removed periodically and transported off site to an appropriate ash storage facility in accordance with all applicable local, State and Federal laws and regulations. The truck washing operation may be discontinued when ambient temperatures drop, or are expected to drop, below 36 degrees Fahrenheit, or otherwise when potential freezing would cause or contribute to unsafe conditions. [**Reference: Consent Decree Section XII. Truck Washing Facilities, paragraph 43]** <u>Mist Eliminators</u> GenOn shall install and maintain a mist eliminator in each FGD/SO_2 absorber for Morgantown Units 1 and 2, as specified in each of GenOn's separate applications for a CPCN to install FGD technology at the Plants. [**Reference:**

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Consent Decree Section XIII. Mist Eliminators, paragraph 44] By 12/31/2009. <u>Reporting Requirements</u> 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]** ***(Completed)*. [Reference: Consent Decree Section XIV. Reporting, paragraph 46]**

<u>Emissions Unit Number(s): F1 and F2: Boilers [SCR Agreement]</u> **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**3-0003**)
<u>Applicable Standards/Limits</u>: The Permittee shall install and continuously operate two selective reduction (SCR) nitrogen oxide control devices on Units 1 and 2. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]** Subject to Paragraph 3 of this Agreement, GenOn agrees that at all times when either Unit 1 or Unit 2 at the Morgantown Generating Station is operating with an SCR control device, particulate matter emissions from each operating Unit, individually, shall not exceed the emission limitation required by Code of Maryland Regulation (COMAR) 26.11.09.06A, or the Unit's baseline actual particulate matter emissions as determined by 40 CFR 52.21(b)(48), whichever is lower. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]** Where baseline actual particulate matter emissions from a Unit subject to this Agreement are lower than the emission limitation required by COMAR 26.11.09.06A, particulate matter emissions from such Unit may exceed the Unit's baseline actual emissions, if and only if, GenOn obtains the Department's approval, by written amendment to this Agreement, to reduce particulate matter

emissions from one or more other emission units at the Morgantown Generating Station by an amount equivalent to the increase in actual particulate matter emissions resulting from the installation of the SCR control device. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]**

The ammonia emissions from Unit 1 and Unit 2, individually, shall not exceed 3 parts per million (ppm) determined by a stack test conducted on each Unit in accordance with EPA or Department approved test protocols no later than 180 days following the Unit's initial startup with the SCR control device. [**Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]**

Testing Requirements:
The Permittee shall conduct a stack test for particulate matter emissions on each Unit in accordance with EPA or Department approved test methods no later than 180 days following the Unit's initial startup with the SCR control device.
[Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]

Monitoring Requirements:
COMAR 26.11.01.11 - Continuous Emission Monitoring Requirements.
"A. Applicability and Exemptions.
(1) The provisions of this regulation apply to:
(a) Fuel-burning equipment burning coal that has a rated heat input capacity of 100 million Btu per hour or greater."
"(2) An owner or operator that is required to install a CEM under any federal requirement is also subject to all of the provisions of this regulation."
B. General Requirements for CEMs.
"(1) An owner or operator subject to this regulation shall:
(a) Before installing a CEM, submit to the Department, for approval by the Department and EPA, a plan containing the CEM design specifications, proposed location, and a description of a proposed alternative measurement method; and
(b) Install and operate a CEM in accordance with the plan approved by the Department and EPA under the provisions of §B(1)(a) of this regulation. "
"(2) The owner or operator of fuel-burning equipment burning coal, with a heat input capacity of 100 million Btu per hour or greater, shall install CEMs to measure and record sulfur dioxide, nitrogen oxide, either oxygen or carbon dioxide, and flow."
"(4) Except as otherwise approved by the Department, if the owner or operator is unable to obtain emissions data from CEMs because of a malfunction of the

CEM for more than 2 hours in duration, the owner or operator shall use the alternative measurement method approved by the Department and EPA. "

"C. Quality Assurance for CEMs. A CEM used to monitor a gas concentration shall meet the quality assurance criteria of 40 CFR Part 60, Appendix F, as amended, which is incorporated by reference, or, if applicable, the quality assurance criteria of 40 CFR Part 75, Appendix B, as amended.

D. Monitoring and Determining Compliance.

(1) General. A CEM required by this regulation is the primary method used by the Department to determine compliance or non-compliance with the applicable emission standards established in any permit or approval, administrative or court order, Certificate of Public Convenience and Necessity, or regulation in this subtitle.

(2) Data Reduction. A CEM used to monitor a gas concentration shall record not less than four equally spaced data points per hour and automatically reduce data in terms of averaging times consistent with the applicable emission standard.

E. Record Keeping and Reporting Requirements.

(1) CEM System Downtime Reporting Requirements.

(a) 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.

(b) The system breakdown report required by §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 data that has met performance specifications for accuracy, reliability, and durability of acceptable monitoring systems, as provided in COMAR 26.11.31, and is producing data.

(2) CEM Data Reporting Requirements.

(a) All test results shall be reported in a format approved by the Department.

(b) Certification testing shall be repeated when the Department determines that the CEM data may not meet performance specifications because of component replacement or other conditions that affect the quality of generated data.

(c) A quarterly summary report shall be submitted 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 ability of the CEM to meet performance specifications of emission data;

(iv) Quarterly totals of excess emissions, installation downtime, and CEM

downtime during the calendar quarter;
(v) Quarterly quality assurance activities;
(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.
(d) All information required by this regulation to be reported to the Department shall be retained and made available for review by the Department for a minimum of 2 years from the time the report is submitted. "

Reporting Requirements:
The Permittee shall submit a stack test protocol to the Department for approval and notify the Department of the scheduled test date at least thirty-(30) days in advance of the test. The Permittee shall submit the stack test results to the Department no later than forty-five (45) days following completion of the test.
[Reference: Agreement between GenOn Mid-Atlantic, LLC and the MDE Regarding Morgantown Generating Station NO_X Pollution Control Project dated April 26, 2006]

Emissions Unit Number(s): F1 and F2: Boilers Cont'd

Alternate Operating Scenario for Emission Units F1 & F2

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 "<u>Specifications for Used Oil</u>.
(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."

<u>Record keeping</u>
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 NO_X, SO_2 and mercury. Regulations .1-.03, .03E, .05 and .06 related to the reductions of NO_X, and SO_2 emissions were submitted to EPA as a revision to Maryland's State Implementation Plan (SIP) on June 12, 2007. The requirements for NO_X, and SO_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): F1 and F2: Boilers Cont'd **F1**: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**) **F2**: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**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_X, SO_2, and mercury as provided in this regulation. B. NO_X Emission Limitations. **Healthy Air Act State-Only enforceable NO_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_X allowances equivalent in number to the tons of NO_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 26.11.27.04 - Determining the Mercury Removal Efficiency for Affected Facilities.

A. The procedures of §§B—F of this regulation shall be used to demonstrate compliance with the 12-month rolling average removal efficiency required for mercury by Regulation .03D of this chapter. The owner or operator of an affected facility shall notify the Department of the compliance demonstration method it has elected from §§D—F of this regulation on or before January 1, 2010, for the compliance period that commences on that date and on or before January 1, 2013, for the compliance period that commences on that date. The owner or operator of an electric generating unit that elects to demonstrate compliance with the required mercury removal efficiency by meeting the mass emissions limitation in §F of this regulation shall utilize that same method for all other electric generating units in the system. Once elected for each affected facility or system, as applicable, the option may not be changed during the designated compliance period, but may be changed for the next compliance period.

B. Determining Mercury Content in Coal and Mercury Flue Gas Emission Rates for Each Affected Electric Generating Unit.

(1) The owner or operator of an electric generating unit subject to this regulation shall, at least once each quarter during a consecutive 18-month period beginning not later than July 1, 2007:

(a) Determine the mercury content of the coal utilized by each affected unit using a test method approved by the Department; and

(b) Conduct a combustion gas test to determine the mercury emission rate in the flue gas upstream of any pollution control measure, including fuel mercury beneficiation.

(2) Combustion gas testing and collection of coal samples to determine the mercury content in coal shall be performed on the same day or days.

(3) The mercury emission rate in the flue gas shall be reported as ounces of mercury per trillion Btu heat input.

(4) Combustion gas testing shall be performed using a test protocol approved by the Department. The test protocol shall be submitted to the Department at least 45 days prior to commencement of testing.

(5) The owner or operator of an affected electric generating unit shall submit to the Department:

(a) The results of tests to determine the mercury content of coal and mercury emission rate in the flue gas upon receipt; and

(b) A demonstration that the combustion gas tests were performed utilizing a coal with a mercury content within the same or lower range as the mercury content of the coal utilized by the electric generating unit during the previous 10 years.

Completed.

C. Determining the Uncontrolled Mercury Flue Gas Baseline for an Affected Facility.

(1) The uncontrolled mercury emission rate in the flue gas of each electric generating unit subject to this chapter shall be determined as the arithmetic average of the quarterly combustion gas tests required by §B of this regulation expressed as ounces per trillion Btu heat input.
(2) The uncontrolled mercury baseline emission rate for an affected facility shall be determined as the heat input weighted average of the emission rates for the coal-fired electric generating units at the affected facility determined in accordance with §C(1) of this regulation.
(3) The uncontrolled mercury baseline emission rate in §C(1) and (2) of this regulation shall be measured upstream of all pollution control measures, including fuel mercury beneficiation. *Completed.*

D. Demonstrating Compliance By Measuring Mercury Removal Efficiency.
Compliance with the required mercury removal efficiency is demonstrated at an affected facility when the heat input weighted average of the mercury emission rate of all coal-fired electric generating units at the affected facility, calculated as a 12-month rolling average, is:
(1) For the 12-month period commencing on January 1, 2010, not more than 20 percent of the uncontrolled mercury emission rate established pursuant to §C of this regulation; and
(2) For the 12-month period commencing January 1, 2013 and thereafter, not more than 10 percent of the uncontrolled mercury emission rate established pursuant to §C of this regulation.

E. Demonstrating Compliance by Meeting a Mercury Emission Rate.
(1) Compliance with the required mercury removal efficiency is achieved for an affected facility when the heat input weighted average of the mercury emission rates of all coal-fired electric generating units at the affected facility, measured as a 12-month rolling average, does not exceed the applicable emission rate in §E(2) of this regulation.
(2) Emission Rates.

Affected Facility	Emission Limits Ounces per Trillion Btu Heat Input Beginning	
	January 1, 2010	January 1, 2013
Morgantown	27	14

F. Demonstrating Compliance by Meeting a Mercury Mass Emission Cap.
(1) Compliance with the required mercury removal efficiency is demonstrated at an affected facility when the mass emissions from all affected facilities in a system, measured in pounds as a 12-month rolling average, do not exceed the applicable emission limits in §F(2) of this regulation.

(2) Mercury Emission Limits.

Affected Facility	Emission Limits Pounds per Year Beginning	
	January 1, 2010	January 1, 2013
Morgantown	127	66

(3) In the event that an electric generating unit at an affected facility subject to this chapter permanently ceases operation, the mass emission limitation in §F(2) of this regulation which is applicable to that affected facility shall be reduced proportionally based on the relative capacity, in megawatts, of all the electric generating units at the affected facility which are subject to this regulation.
(4) In the event that an entire affected facility within a system permanently ceases operation, the total mass emission limitation in §F(2) which is applicable to the system shall be reduced by the mass emission limitation applicable to the affected facility.
(5) Except during periods of startup, shutdown, malfunction or maintenance, the owner or operator of an electric generating unit shall ensure that mercury control measures are continuously employed on each unit and properly adjusted for optimal control taking into consideration the operating conditions.

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_X and SO_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): F1 and F2: Boilers Cont'd

F1: Unit 1: manufactured by CE-Alstom and rated at 640 MW. (**3-0002**)
F2: Unit 2: manufactured by CE-Alstom and rated at 640 MW. (**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)."

(2) COMAR 26.04.10.05 - Storage

"A. A person may not store coal combustion byproducts except in accordance with the provisions of this regulation.

B. A person may not store coal combustion byproducts directly on the surface of the ground or in an unlined surface impoundment, pit, pond, or lagoon without the authorization of the Department.

C. A person shall store coal combustion byproducts in a manner that prevents contact with waters of this State and that is designed either to minimize contact with precipitation or to collect leachate that may result from contact with precipitation.

D. A person may not use a storage system for coal combustion byproducts unless the storage system is:
(1) Designed, constructed, and installed to contain coal combustion byproducts and contaminants in the coal combustion byproducts and prevent them from being released to the environment; and
(2) Provided with a roof or other protections to prevent nuisance, air pollution, and unlawful discharges of contaminated stormwater or leachate to the waters of this State.

E. A person may not store coal combustion byproducts in an area likely to pollute the waters of this State.

F. Responsibility for the prompt control, containment, and removal of any released coal combustion byproducts or for placing coal combustion byproducts in a position likely to pollute the waters of this State shall be with the person responsible for the release, and with the owner and operator of the facility, site, or storage system where the release occurred. This responsibility shall continue until removal or clean up of any contamination or pollution from the release has been accomplished to the satisfaction of the Department.

G. The Department may impose specific requirements for the storage of coal combustion byproducts upon a determination that storage of coal combustion byproducts has caused or is likely to cause a discharge to the waters of the State, is a nuisance, or otherwise poses a threat to public health or the environment.

H. The owner and operator of a facility, site, or storage system shall ensure that:
(1) A release of coal combustion byproducts during storage operations due to spilling or overflowing does not occur;
(2) Adequate storage space is available to handle the volume of coal combustion byproducts generated and to be stored; and
(3) Transfer, handling, and storage operations are performed in a manner that

shall prevent, contain, and clean up spills of coal combustion byproducts."

Emissions Unit Number(s): STAR

The STAR facility processes fly ash in to a Portland cement substitute. The STAR facility is made up of a 140 mmBtu/hr process reactor equipped with a supplemental 65 mmBtu/hr propane heater and a 20 mmBtu/hr propane duct burner. The unit is equipped with a fabric filter baghouse and wet flue gas desulfurization scrubber system. Exhaust gases are directed through a 125 foot stack. The STAR process facility includes a fly ash receiving feed silo and a truck unloading facility, a 30,000 ton product storage dome which includes a product silo with a truck loading facility. The reactor, the storage dome and silos are equipped with pneumatic ash transfer systems. (**6-0150 (CPCN 9229)**)

[Reference: CPCN 9229]
A-36. Annual emissions from the Morgan STAR Facility shall be less than the following in consecutive 12-month period, rolling monthly, inclusive of emissions during periods of startup, shutdown and malfunction:

Pollutant	Emission Limit for Entire Morgantown STAR Facility (pounds per year)
Mercury (Hg)	5

A-37. GenOn shall conduct annual performance stack tests of the STAR process reactor to determine compliance with COMAR Title 26, Subtitle 11 for mercury [COMAR 26.11.01.04A. The performance stack tests shall be conducted with a representative composite of fly ash typically combusted in the STAR process reactor at that time. GenOn shall submit a stack test protocol to MDE-ARA for approval, in accordance with Condition A-25.

A-38. GenOn shall analyze samples of the unprocessed fly ash entering the STAR process reactor and the processed fly ash exiting the STAR process reactor or mercury concentration on a monthly basis.

A-39. GenOn shall submit a quarterly monitoring report to MDE-ARA, postmarked by the 30th day following the end of each calendar quarter that includes the following information for the STAR Facility:
(a) The actual emissions of mercury for the STAR Facility based on a consecutive 12-month period, rolling monthly. An algorithm, including example calculations, emissions factors, and monthly throughput, explaining the method used to determine emission rates shall be submitted to MDE-ARA for review and

approval at least 60 days prior to the initial quarterly monitoring report. Subsequent submittals of the algorithm and sample calculations are only required if GenOn changes the method of calculating emissions, changes emissions factors, or if requested by MDE-ARA; and
(b) The analysis results for the monthly samples of the unprocessed fly ash and processed fly ash required under Condition A-38.

A-40. GenOn shall maintain any records necessary to determine the STAR Facility mercury actual emissions. Emissions shall be calculated monthly and annually based on a consecutive 12-month period, rolling monthly for comparison with the annual emission limit in Condition A-36.