Appendix D:
Documentation of
Local SO_2 Reductions

West Virginia Division of Air Quality
601 57th Street, SE
Charleston, WV 25304

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Table of Contents

Appendix D: Documentation of Local SO_2 Reductions

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west virginia department of environmental protection

Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Phone: 304 926 0475 • FAX: 304 926 0479

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

November 5, 2015

Dan Fearday, Plant Manager
Rain CII Carbon LLC
State Route 2 South
Moundsville, WV 26041

Re: Company ID No. 05100011
Permits R13-0563, 13-0588, 13-0662, 13-2095,
13-2612A & R30-05100011-2014
Moundsville Calcining Plant

Dear Mr. Fearday:

Pursuant to your letter dated October 14, 2015, Permits R13-0563, 13-0588, 13-0662, 13-2095, 13-2612A and R30-05100011-2014 have been placed as inactive. Once verified by our Compliance and Enforcement Section, this facility will be placed as Status 90 – permanently shutdown.

Please bear in mind, any future operation may require a permit pursuant to 45CSR13.

Sincerely,

William F. Durham
Director

WFD/jlr

c: Bryan Schuetze
Robert Keatley
File Room

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west virginia department of environmental protection

Division of Air Quality
131A Peninsula Street
Wheeling, WV 26003
Phone: 304-238-1220 Fax: 304-238-1136

Earl Ray Tomblin, Governor
Randy Huffman, Cabinet Secretary
www.wv.dep.gov

TO: Eric Weisenborn, ERPM II
FROM: Al Carducci, ERS III
DATE: January 8, 2016
FILE: Rain CII Carbon LLC
SUBJECT: Closure Evaluation
PLANT ID: 051-00011

Permit: R30-05100011-2010
Regulation(s): 2,4,6,7,10,11,13,30
Compliance Status: 90

On January 8, 2016, Greg Paetzold, ERS 3 and I conducted a closure inspection of the CII Carbon LLC facility located at 8245 Energy Rd., Moundsville, West Virginia. Upon arriving at the facility, we were greeted by Mrs. Bonnie Vetanze, Plant Manager, who accompanied us on an inspection of the facility grounds.

The entrance gate of the facility was half shut and a lock was attached. There was no activity taking place at the site and all small storage piles have been removed. Mrs. Vetanze informed us that the facility is up for sale.

The calcining operations have been shut down since January 1, 2014. The official closure date of the plant was October 9, 2015.

Alfred A. Carducci, ERS III

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AEP AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215
aep.com

ID # R30-05100006-2009
Reg T5 IPR
Company AEP
Facility Kammer Initials CDM

June 30, 2015

Mr. William F. Durham, Director
West Virginia Department of Environmental Protection
Division of Air Quality
601 - 57th Street
Charleston, West Virginia 25304

RE: Request to Revoke Title V Permit
AEP Generation Resources, Inc.
Kammer Plant (R30-05100006-2009)

Dear Director Durham,

As you know AEP Generation Resources, Inc. Kammer Plant was permanently retired on June 1, 2015 after the 45 day compliance extension for the Mercury and Air Toxics Standards (MATS) Rule expired on May 31, 2015. As the facility continues to go through decommissioning steps in the coming months, we will keep WVDEP updated on progress.

In accordance with recent discussions with your office staff concerning the Title V air operating permit for Kammer Plant, we are requesting that the Title V Permit for the facility (R30-05100006-2009) be revoked as of June 30, 2015. Accordingly, based on previous discussions with your staff, the facility will not be required to pay Title V operating fees which would cover the operating period July 1, 2015 through June 30, 2016.

We wish to thank you and your staff for your cooperation and assistance in our efforts to maintain compliance with the air program requirements over the long history of operation of the Kammer Plant.

Should you have any further questions or need additional information, please contact Greg Wooten (AEP Air Quality Services) at (614) 716-1262.

Daniel L Moyer

D. L. Moyer
Plant Manager
Kammer Plant

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JUL 02 2015
WV DEP / DIV OF AIR QUALITY

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ID # R30-05100006-2009
Reg T5 IPR
Company AEP
Facility Kammer Initials CDM

dep

west virginia department of environmental protection

Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Phone: 304/926-0475 • FAX: 304/926-0479

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

October 22, 2015

SCANNED

Mr. D. L. Moyer
Plant Manager
American Electric Power
P. O. Box K
Moundsville, WV 26041

Re: Kammer Plant
Permit No. R30-05100006-2009

Dear Mr. Moyer:

AEP's request for Title V permit R30-05100006-2009 for the Kammer Plant to be placed inactive is hereby granted. This determination is based upon the following:

1) Your letter dated June 30, 2015 informing the Division of Air Quality (DAQ) that the electric generating units (Units 1, 2, and 3) were permanently retired on June 1, 2015;

2) Submittal of a Certified Emissions Statement (CES) Registration Form dated July 28, 2015 for emissions from the coal and limestone handling equipment that will remain in place at the Kammer Plant;

3) Approval of Class I Administrative Update R13-1582D on October 14, 2015 which removed coal processing equipment from the permit that if installed would have caused the facility to become subject to 40 C.F.R. 60 Subpart Y.

With the shutdown of the electric generating units, only the coal and limestone handling systems at the facility will remain operational. The CES Registration Form indicated that emissions from the coal and limestone handling systems are not major for criteria pollutants and hazardous air pollutants (HAPs); are not subject to a standard, limitation or other requirement promulgated under §111 or §112 of the Clean Air Act; and are not an affected source under the Acid Rain Program of Title IV of the 1990 Clean Air Act Amendments. Therefore, the coal and limestone handling systems are not subject to Title V.

The Title V operating permit for this facility will be placed inactive. Also, as requested in your letter dated July 24, 2015, DAQ acknowledges the withdrawal of your Title V renewal application for the Kammer Plant received on November 4, 2013. If any changes are made at the

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facility which would cause the source to become subject to Title V, a complete application to obtain a Title V operating permit must be submitted within twelve (12) months after commencing operation of the change which triggered Title V applicability.

Since the source is no longer subject to 45CSR30, payment of fees under 45CSR30 based on emissions will no longer be required and the facility will pay fees required under 45CSR22 and shall maintain a Certificate to Operate in accordance with 45CSR§22-4.1 for operation of the coal and limestone handling systems. The facility shall begin paying fees under 45CSR22 for the operating year beginning on July 1, 2015.

After thorough review and internal discussion, the agency has elected not to pursue the Title V fees for emissions from the Kammer Plant for the calendar year 2014. Please note that this decision reflects neither an official agency policy nor adoption of AEP's position regarding the timing and assessment of Title V fees. This decision applies only to the Title V fees for the aforementioned facility for calendar year 2014 emissions. It should not be considered dispositive for any purpose, including but not limited to current or future Title V fee issues.

If you have any questions, please feel free to contact Carrie McCumbers, Title V Program Manager, at (304) 926-0499 ext. 1226.

Sincerely,

William F. Durham
Director

cc: Gregory J. Wooten
AEP Air Quality Services Engineer

west virginia department of environmental protection

Division of Air Quality
601 57th Street, SE
Charleston, WV 25304-2345
Phone: 304 926 0475 • Fax: 304 926 0479

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

ENGINEERING EVALUATION/FACT SHEET

B ACKGROUND INFORMATION

Application No.:	R14-0027D
Plant ID No.:	051-00002
Applicant:	Eagle Natrium LLC
Facility Name:	Natrium Plant
Location:	New Martinsville
NAICS Code:	325181 & 325110
Application Type:	Modification
Received Date:	November 01, 2013
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$4,500.00
Date Paid:	October 17, 2012
MACT Fee Date Paid	November 4, 2014
Complete Date:	December 4, 2013
Due Date:	March 3, 2014
Applicant Ad Date:	November 4, 2013
Newspaper:	*Moundsville Daily Echo*
UTM's:	Easting: 512.7 km Northing: 4,399.6 km Zone: 17
Description:	The application is for the conversion of Boilers #5 and #6 to natural gas.

DESCRIPTION OF PROCESS

No. 5 Boiler currently burns pulverized coal and utilizes natural gas for start-up and flame stabilization. The dry bottom wall fired unit began operation in 1966. It is equipped with a dry, cold side, electrostatic precipitator and low NO_x burners with over fire air. Low-NOx burners with the over fire air configuration were installed in 2004. This boiler was specifically configured to Turbine #7, which is a 70 megawatt (MW) steam turbine/generator set.

No. 6 Boiler was installed in 1993. It is a Zurn 181 MMBtu/hr boiler designed to burn hydrogen gas. However, it uses natural gas for start-up and stabilization procedures. The primary purpose of this unit is to generate steam that produces electricity and the remaining heat energy in the steam, after being exhausted by the turbines, is then used in the manufacturing process at the Natrium Plant. All of the electricity generated from these boilers is consumed by the Natrium Plant.

Eagle Natrium proposes to re-configure Boiler #5 to be completely fired by natural gas, which will require the heat input size of the unit to be increased up to 999 MMBtu/hr. For Boiler #6, Eagle Natrium proposes to configure Boiler #6 to be fired completely on natural gas and retain the ability to consume hydrogen gas. The main reason for the modification is to allow these two emission units to comply with the requirements of Subpart DDDDD of 40 CSR 63 (Boiler Maximum Available Control Technology (MACT)) as "Gas 1" affected sources.

SITE INSPECTION

On December 5, 2012, the writer visited the site. Ms. Erika Baldauff, Engineer for Eagle Natrium, accompany the writer during this visit. The nature of this inspection was for the proposed installation of the #3 HCL Acid Production Unit. This visit included a stop at the power house. The proposed changes to No. 5 and 6 Boilers should result in actual decreases in potential and actual emissions. Since the last full onsite inspection determined that the facility was operating within compliance, the writer deemed a follow-up visit to the facility was not warranted.

ESTIMATE OF EMISSION BY REVIEWING ENGINEER

The applicant has determined that the heat input of Boiler #5 would have to be increased up 999 MMBtu/hr to yield the original designed steam output of 750,000 lb per hour. Using this new heat input rating and other design/operating parameters (i.e. excess air, percentage of over fire air), the applicant developed emission factors for oxides of nitrogen (NO_x) and carbon monoxide (CO) that should be reasonably achievable from most burner manufacturers that could perform this retrofit project. The target for NO_x and CO was 0.16 lb per MMBtu and 100 ppm respectively.

The following information was used to predict the emission potential of No. 5 Boiler before and after this project.

Constants of No. 5 Boiler:

Maximum Steam Production Rate:	750,000 lb/hr @ 1,300 psig
Maximum Coal Firing Rate:	35.88 tons per hour (tph); 303,787 tons per year (tpy)
24 –hour Maximum Natural Gas Fired Rate:	892.1Mscf per hour
Higher Heating Valve (HHV) of Natural Gas:	1,020 Btu/scf

Table #1 – Emissions from No. 5 Boiler			
Pollutant	**NOx (lb/hr)**	**PM (lb/hr)**	**SO_2 (lb/hr)**
Potential/Permitted Limits	702	79.0	1,479.0
Emission from Natural Gas at Maximum Heat Input Rate	159.84	0.46	0.5
Net Difference	-542.16	-78.54	-1,478.5

Other Pollutants that were estimated are carbon monoxide (CO), volatile organic compounds (VOCs) and carbon dioxide equivalent (CO_2e).

Table #2 – Other Emissions from No. 5 Boiler			
Pollutant	**CO (lb/hr)**	**VOCs (lb/hr)**	**CO_2e lb/hr)**
Potential w/100% Coal Before	17.94	2.15	182,013.79
Emission w/Natural Gas After	81	8.12	116,980.9
Net Difference	63.06	5.97	-65,032.89

No. 6 Boiler was originally designed and constructed to burn hydrogen gas. Thus, the heat input needed for the boiler to generate 112,000 lb/hr of steam is nearly the same regardless of the fuel (natural gas or hydrogen gas). Again, Eagle Natrium has basically set the emission factor parameters on what should be reasonably achievable from most burner manufacturers that could provide equipment for this retrofit project. The targets for NOx and CO emission parameters are 0.04 lb/MMBtu and 100 ppm respectively.

The emission change as a result of this conversion is much different than for No. 5 Boiler. Hydrogen gas burned in No. 6 Boiler is a by-product from the Chlorine Circuits of 6, 7, and 8 at the facility. Burning hydrogen should yield just water and thermal NO_x. Natural gas combustion yields nearly emissions of all criteria pollutants except for lead.

The following information was used to predict the emission potential of No. 6 Boiler before and after this project.

Constants of No. 6 Boiler:

Maximum Steam Production Rate:	112,000 lb/hr @ 865 psig
Maximum Hydrogen Gas Firing Rate:	3,112 lb per hour (pph); 567 M scf per hour
24 –hour Maximum Natural Gas Fired Rate:	165.5 Mscf per hour
HHV of Natural Gas:	1,020 Btu/scf
HHV of Hydrogen Gas:	320.89 Btu/scf (winter) 309.54 Btu/scf (summer)

Table #3 – Emissions from Boiler #6		
Pollutant	Permitted Limits (lb/hr)	After Conversion (lb/hr)
PM Filterable/Condensable Fractions	0.2	0.09
PM_{10} Filterable/Condensable Fractions	-	0.09
$PM_{2.5}$ Filterable/Condensable Fractions	-	0.07
Sulfur Dioxide (SO_2)	0.1	0.1
Oxides of Nitrogen (NO_x)	10.6	7.29
Carbon Monoxide (CO)	1.3	15
Volatile Organic Compounds (VOCs)	0.1	1.53
Total Hazardous Air Pollutants (HAPs)	-	0.33
Carbon Dioxide Equivalent* (CO_2e)	-	21,311.84

Eagle Natrium plans on operating both units on a continuous basis. Thus, no limitation for the annual operating schedule was proposed. Therefore, potential annual emissions were based on operating schedule of 8,760 at full heat input for both units. These emissions are summarized in the following table.

Table #4 – Annual Emissions from Both Boilers			
Pollutant	Boiler #5 (tpy)	Boiler #6 (tpy)	Total Emission (tpy)
PM Filterable/Condensable Fractions	2.07	0.38	2.45
PM_{10} Filterable/Condensable Fractions	2.07	0.38	2.45
$PM_{2.5}$ Filterable/Condensable Fractions	2.07	0.31	2.38
Sulfur Dioxide (SO_2)	2.19	0.44	2.63
Oxides of Nitrogen (NO_x)	700.10	31.93	732.03
Carbon Monoxide (CO)	354.78	65.7	420.48
Volatile Organic Compounds (VOCs)	35.57	6.7	42.27
Total Hazardous Air Pollutants (HAPs)	7.8	1.45	9.25
Carbon Dioxide Equivalent* (CO_2e)	512,376.35	93,345.84	605,722.19

REGULATORY APPLICABLILITY

Nos. 5 and 6 Boilers are currently subject to Rules 2 & 10 (45 CSR 2, 45 CSR 10) for PM and SO_2, and Subpart DDDDD of Part 63 (National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) referred to as the Boiler MACT. Only No. 5 Boiler is subject to the Clean Air Interstate Rule (CAIR) Control of Ozone Season Nitrogen Oxides Emissions (45 CSR 40). This proposed change in operation does not affect or change this unit's applicability status with these rules. However, the proposed modification will change the way these emission units demonstrate compliance with the emission standards from these rules will be explained in the remainder of this section except for the 45 CSR 40 (WV CAIR Rule). Under CAIR, Eagle Natrium will still be required to obtain allowances to cover NO_x emissions from No. 5 Boiler that were emitted during the Ozone Season.

Subpart Db of Part 60

This proposal has the potential to make these units affected sources to Subpart Db of the New Source Performance Standard as a reconstructed source or modification in 40CFR 60.14(a), which states "… operational change to an existing facility which results in an increase in the emission rate in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act…". No 5 Boiler meets the basic criteria of a potentially affected source under Subpart Db (i.e. indirect heat exchanger (boiler) with a heat input of greater than 100 MMBtu/hr). The pollutants that this subpart set a standard for are PM, SO_2, and NO_x.

Because Eagle Natrium is attempting to re-gain lost steam generating capacity due to the installation of low-NO_x burners, the source had to make a demonstration to prove the project does not constitute "reconstruction" as defined under Part 60. Under 40 CFR §60.15(d), reconstruction is triggered if the "fixed capital cost" of a project exceeds 50 percent that would be required to construct a comparable new emission unit. For this particular project, Eagle Natrium estimated the fixed capital cost with the conversion of No. 5 Boiler is projected to be 7.9 million dollars and the cost of a replacement unit for No. 5 Boiler to be 37 million dollars. Thus, the cost of the conversion project for No. 5 Boiler is just 21% of a replacement unit and does not meet the Part 60 definition of reconstruction. Therefore, No. 5 Boiler will not be an affected source under Part 60.

The maximum design heat input of No. 6 Boiler will be 182 MMBtu/hr, which exceeds the subparts' applicability threshold of 100 MMBtu/hr. No. 6 Boiler was constructed after June 19, 1984 applicability date of this subpart. Permit R13-1637 established a less than 10% capacity factor limit for the unit to be fired on natural gas, which excluded the unit from the NO_x emission limitation of §60.44b(b) according to §60.44b(e). This limit was retained in Permit R13-1637A in Condition 4.1.3. The proposed modification requests the capacity of the unit to use 100% natural gas means that the NO_x limit of §60.44b becomes in effect upon re-start from the conversion.

For natural gas burning affected units under Subpart Db, only the NO_x emission standard is applicable to those units. Boiler #6 has a heat release rate of 89,435 Btu/hr-ft^3. The heat release rate is a function of the furnace volume and design heat input rate. Subpart Db classifies Boiler #6 as a "high heat release rate" unit. According to 40 CFR §60.44b(a), Boiler #6 will be subject to the NO_x limit of 0.20 lb per MMBtu/hr. Eagle Natrium predicts the NO_x rate with the low NOx burners and fuel gas recirculation to be 0.04 lb per MMBtu from boiler #6. Under the subpart, Eagle Natrium will be required to use continuous emission monitors to demonstrate compliance with the limit on a 30 day rolling average.

Rules 2 &10

For No. 6 Boiler, this project does not affect how this unit will comply with the PM and SO_2 standard in these rules. The potential of these two pollutants will remain in significant with the switch to natural gas. Both of these rules have provisions that recognize the insignificant amount of PM and SO_2 emissions generated from burning natural gas, which excludes them from the requirements of periodic testing and monitoring.

No. 5 Boiler has been subject and complying with the PM and SO_2 emission standards and monitoring requirements. Eagle Natrium currently ensures a specific number of fields of the electrostatic precipitator to be in service and conducts monthly visible emission observations with periodic PM testing based on the schedule outlined in 45 CSR 2A. For Rule 10, the source operates and maintains a SO_2 continuous emission monitor.

The conversion for No. 5 Boiler will allow the operator to discontinue these monitoring measures. The margin of compliance for PM emissions from the unit will increase by 99% without the use of an add-on control device. For SO_2 emissions, No. 5's new potential will be less than a half percent of the existing permitted limit of 1479 lb/hr.

After the conversion, the permit will establish compliance with these two rules by restricting the fuel type to pipeline quality natural gas for No. 5 and hydrogen/pipeline quality natural gas for No. 6.

PSD & Nonattainment Permitting

The Natrium Plant is classified as an existing major source under 45 CSR14. Therefore, a PSD review of this project must be conducted. PSD looks at long term emissions to determine if a project needs to undergo the Major Source Permitting Process. This type of applicability analysis only looks at criteria pollutants such as PM, PM_{10}, $PM_{2.5}$, CO, NO_x, SO_2, VOCs, lead (Pb), and CO_{2e}. With these pollutants in consideration, the review will look to see if this project would result in a "significant net increase" of the individual pollutant being evaluated.

The first step in the netting process is to determine if the project by itself would result in an emission increase greater than the significant level for the respective New Source Review (NSR) pollutant.

Table #5 Step One of PSD Applicability			
Pollutant	New Potential from the No.5 & 6 Boilers (tpy)	Significance Threshold (tpy)	Significance Trigger (Yes/No)
PM	2.45	25	No
PM_{10}	2.45	15	No
$PM_{2.5}$ Direct	2.38	10	No
SO_2	2.63	40	No
NO_x (precursor of Ozone and $PM_{2.5}$)	732.03	40	Yes
CO	420.48	100	Yes
VOCs	42.27	40	Yes
CO_2 equivalent (CO_{2e})	605,722.19	75,000	Yes

Since the project poses a significant increase for NO_x, CO, VOCs, and greenhouse gases in the form of CO_2e, the next step is to compare the new potential for these four pollutants with the baseline emissions from No. 5 and No. 6 Boilers. Eagle Natrium selected operating years of 2004 and 2005 to establish baseline actual emissions (BAE) for this project. The emissions from these years are based on different sources of data. CO, NO_x, and CO_2 releases were acquired using continuous emission monitoring system (CEMs). VOCs emissions were based on emission factors published in AP-42.

Table #6 Step Two - Baseline Actual Emissions				
Pollutant	CO	NO_x	VOC	CO_2e
Unit	Tpy	tpy	Tpy	tpy
No. 5	199.09	1178.25	7.17	608884.12
No. 6	0.13	22.76	0.01	172.20
Baseline Total from 5 & 6	199.22	1201.01	7.18	609056.32
New Potential	420.48	732.03	42.27	605,722.32
Net Difference	221.26	-468.98	35.09	-3,334
Significance Threshold (tpy)	100	40	40	75,000
Is Significance Met?	Yes	No	No	No

Since the project is still posing a significant increase for CO emissions, the applicant has to conduct a netting analysis to determine if the project must be treated as a major modification under Rule 14. Thus, Eagle Natrium has identified all creditable increases and decreases at the facility that occurred during the contemporaneous period. These changes are identified in the following table.

Table #7 Facility Wide CO Emission Changes	
Unit	CO (tpy)
Installation of #1 HCl Synthesis Unit	43.80
Installation of #2 HCl Synthesis Unit	43.80
Installation of #3 HCl Synthesis Unit	83.22
Shutdown of #3 Boiler	-154.76
Shutdown of #4 Boiler	-149.42
Sum of CO Emission Change	-133.36
Net of #5 & 6 Boilers Difference from Table #6	221.26
Net CO Emission Change	87.9

The net CO change of this project is less than the 100 tpy significant threshold. Therefore, this project does not represent a "net significant" increase of CO emissions and a major modification of a major source. This concludes the PSD applicability review of this project.

The Natrium Plant is located in Marshall County. Marshall County was designated as attainting the National Ambient Air Quality Standard (NAAQS) in September 2013. Therefore, Rule 19 does not apply.

Boiler MACT

The Natrium Plant is a major source for hazardous air pollutants (HAPs). This project will reduce HAP emissions from the facility but will remain as a major source of HAPs. Thus, the Boilers 5, and 6 are affected sources under Subpart DDDDD of Part 63.

Natural gas is classified under this subpart as a "gas 1" fuel. However, hydrogen gas is not defined in this subpart specifically. However, Eagle Natrium will make the case that the hydrogen gas produced at the facility and consumed by No. 6 Boiler meets the definition of "other gas one fuels", which is a gas with a mercury concentration of less than 40 micrograms per cubic meter of gas (40 CFR §63.7575). Units consuming a fuel classified under "gas 1" or "other gas 1 fuel" are only subject to the work practices requirement of this subpart, which are periodic tune-ups for each unit and a one-time energy assessment of the facility.

Both of these boilers currently operate with oxygen trim systems and will be equipped with oxygen trim after the conversion. Thus, subsequent tune-ups for these units will have to be conducted once every five years.

The hydrogen fuel for No. 6 Boiler is supplied from the chlorine circuits at the facility. There are three chlorine circuits, including Circuits 6, 7 and 8. The hydrogen gas generated from

Circuits 6 and 8 does not exceed the mercury limit as defined in the subpart. Conversely, the hydrogen from Circuit 7 will have the potential to exceed the mercury threshold as defined. The hydrogen from Circuit 7 will be combined with hydrogen from other two circuits to meet this threshold level of an "other gas 1 fuel". Under the Chlor-Alkail MACT (Subpart IIIII of Part 63), Eagle Natrium is required to continuously measure the actual mercury concentration in the hydrogen produce from Circuit 7. The Boiler MACT requires sources using "other gas 1 fuel" to prepare and submit site specific fuel analysis plan for approval to determine if the gas meets the definition. Once the plan is approved, Eagle Natrium will have to implement it and determine if the hydrogen fuel meets the criteria of an "other gas 1 fuel".

Under Part 63, the definition of reconstruction is the same as under Part 60. Thus, this modification for No.5 Boiler does not meet this definition. The cost of modification for No.6 Boiler was estimated at 1.3 million dollars. To completely replace it with a new unit was estimated at 4.2 million dollars. The projected cost of the project for No. 6 Boiler is less than 29% of a new boiler. Therefore, this project does not trigger reconstruction for either boiler under Part 63. Therefore, both units are treated as existing units under the Boiler MACT.

The compliance date for the Boiler MACT is January 31, 2016. On March 19, 2014, the applicant filed a compliance date extension request. Eagle Natrium requested an extension to cover Nos. 3, 4, and 5 Boilers to the completion of the conversion project or until December 2016, whichever is sooner. The modification for No. 6 Boiler is projected to be complete by November 2015. Thus, No. 6 Boiler is expected to be operating in compliance with the MACT standard prior to the compliance date of January 31, 2016.

No.5 Boiler is scheduled to be taken down at the end of February 2016, after the compliance date, to be converted for natural gas firing. It has been estimated the conversion project will take about three months to complete for No. 5 Boiler. For Eagle Natrium to continue operating the Natrium Plant, the applicant will have to purchase electricity externally. This option poses risk to potential electric power curtailments at the discretion of the utility operator.

Usually, extensions under Part 63 can be up to a full year for existing sources (four year compliance schedules). Because Eagle Natrium' s proposed plan for this conversion project required Nos. 3 and 4 Boilers to be permanently shutdown to avoid PSD, the driver for the length of the extension is the outcome of the netting analysis under Rule 14. Thus, the extension has to become part of the permitting process.

The extension request was approved on April 10, 2014 and will be incorporated into the permit, which includes the efforts the applicant will implement to minimize HAP emissions during the extension period. After the conversion is complete, Nos. 5 and 6 Boilers will be capable of meeting the requirements of the MACT Standard without the use of any add on control device(s).

Rule 13

Eagle Natrium prepared and submitted a complete application, paid the filing fee, and published a Class I Legal ad in the *Moundsville Daily Echo* on November 4, 2013. This modification will not make these emission sources applicable to any additional regulations, except for Subpart Db for No. 6 Boiler. The Natrium Plant will remain as a major source and be required to maintain a valid operating permit in accordance with 45 CSR 30. Eagle Natrium included Attachment S with this application to have the changes made in Permit R14-0027D be included in the facility's Title V Permit.

Because the netting analysis in this application relies on the CO reductions from shutting down Nos. 3 and 4 Boilers, to avoid a major modification under Rule 14, Notice Level C procedures of Rule 13 needs to be executed for this particular application during the upcoming public comment phase.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

Nos. 5 and 6 Boilers will not emit any new pollutants that aren't already being emitted by the unit before this modification. The HAPs emissions from No. 5 Boiler after the conversion to natural gas will significantly reduce actual HAPs emission. Just looking at 2013 actual reported emissions from No. 5, hydrochloric acid (HCl), which is one of the 187 HAPs, could have been reduced by 183 tons in 2013. For No. 6 Boiler, this modification will have little effect on HAPs emitted from the unit. Therefore, no information about the toxicity of the hazardous air pollutants (HAPs) is presented in this evaluation.

AIR QUALITY IMPACT ANALYSIS

The writer deemed that an air dispersion modeling study or analysis was not necessary, because the proposed modification does not meet the definition of a major modification of a major source as defined in 45CSR14.

MONITORING OF OPERATIONS

Under CAIR and Subpart Db, Nos. 5 and 6 Boilers will be required to continuously monitor NO_x emissions. As outlined in this evaluation, this project is within 90% of the trigger level for CO under Rule 14 even with the shutdown of Nos. 3 and 4 Boiler. Thus, the monitoring of actual CO emissions is warranted to ensure that the project does not exceed the CO limits and potentially void the netting analysis. Eagle Natrium had proposed the use of a continuous emission monitoring system (CEMS) for both of these pollutants, oxygen, and carbon dioxide. During the application review, the applicant inquired about the use of predictive emission monitoring systems (PEMS).

PEMS is not exactly the same CEMS. However, EPA has developed a specific performance specification (PS-16) for PEMS and has approved the use on case-by-case basis for use of demonstrating compliance with federal emission standards/emission trading programs as acceptable alternative to CEMS. The writer believes that the use of PEMS would be an acceptable application for these two units if installed in accordance with PS-16.

After careful studying of Subpart Db of Part 60, 40 CSR 40, Part 75, the agency does not have the authority to approve the use of PEMS in lieu of CEMS for demonstrating compliance with these rules. 40 CSR §40-71.6 refer to process outline Subpart E of 40 CFR Part 75 to obtain approval of alternative monitoring from the Administrator, which will be the Clean Air Markets Division of the EPA.

Subpart Db does not mention an alternative form of monitoring in lieu of CEMS for NO_x compliance. Thus, it must be approved by the Administrator, as well, either at Region III and/or Emissions, Monitoring & Analysis Division at OAQPS of the EPA.

Both types of monitoring systems will either measure or predict NO_x and CO emissions. Other data required for CAIR and Subpart Db are exhaust flow rate and heat input. EPA allows measuring fuel usage to determine flow rate using the procedures outlined in Method 19 and heat input by using engineering calculations.

The writer recommends using either CEMS or PEMS for demonstrating compliance with the NO_x and CO emission limits. The proposed limits are in terms of lb of pollutant per MMBtu on a 30 day rolling average basis. To cap the annual emissions without establishing a second limit, the writer recommends limiting the annual heat input on a 12 month rolling total per unit. This approach simplifies the requirements, standardizes the term without creating an inflexible condition for No. 6 Boiler, which will be consuming two different fuels.

CHANGES TO PERMITS R14-0027B & R13-1637A

Permit R14-0027B covers No. 3, 4, and 5 Boilers for the Natrium Plant. These boilers are coal fired units that are subject to the applicable requirements of Rule 2 (PM), and 10 (SO_2). The permit established the mass based limits for PM and SO_2 for each of these boilers in two different tables, one for each pollutant. In addition to these limits, the permit established a total hourly SO_2 limit from the all three units of 3,766.8 lb/hr (Permit R14-0027A) for compliance with Regional Haze and Best Available Retrofit Technology (BART) State Implementation Plan. Permit R14-0027A addressed the BART mandates for the No. 5 Boiler as a BART unit.

Nevertheless, the State of New Jersey commented on the State of West Virginia's BART SIP submittal that the emission reductions should be prior implemented before approving the SIP instead of the BART Compliance Dates. Thus, the permittee elected to accept the SO_2 reductions earlier that stipulated in Permit R14-0027A, which created Permit R14-0027B. Permit R14-0027B left a total SO_2 limit for No. 3 and 4 Boilers of 2,288 lb per hour (Condition A.6.) and total combine limit of SO_2 limit of 3,767 lb per hour from all three units.

These total limits are direct sums of the individual limits. It would have made sense to have a total SO_2 for No. 3 and 4 Boiler, which vents to a common stack or implementing the original BART compliance date. The permittee operates separate SO_2 CEMs on the exhaust of each unit before mixing into the common stack. The writer believes that compliance is being monitored with SO_2 CEMs from each unit that the permitted limit should only reflect the individual and not the summation of these individual limits. Therefore, the combined SO_2 limits in Conditions A.6. and A.10. were not carried into this proposed permit.

Boiler No. 3 will be permanently shut down as result of this modification. Of the existing conditions in Permit R14-0027B, all were retained except for the lb/MMBtu for PM in A.4. and A.7. to install low-NO_x burners. Both limits are redundant or meaningless with the other limits in place. The permit establishes mass limit for PM and lb/MMBtu for NO_x emissions with specific means to demonstrate compliance.

The writer re-organized the existing limits/conditions into three individual conditions, one for each unit (Condition 4.1.1. for No. 3; Condition 4.1.2. for No. 4; Condition 4.1.3. for No. 5). The existing limits for these units were incorporated into item a. of these conditions. Other changes to the existing conditions was stating the compliance with the SO_2 limit to be determined on a continuous 24 hour average period as stipulated in 45 CSR §10-3.8.

The existing permit required CEMs for NO_x from No. 3 and SO_2 from No. 5. The permittee has certified CEMS for NO_x, SO_2, CO_2, and volumetric flow rate for Nos.3, 4, and 5 boilers. There are un-certified CO CEMS on the three units too. The applicant identified the use of SO_2 CEMS for compliance with in the facility's Rule 10 monitoring plan submittal pursuant to 45 CSR §10-8.2.c.

Part 75 has procedures for missing data or developing method to handle bias data. Acid Rain program needed these procedures to make the "cap-trading" program to work as it was designed to do. These procedures are not normally accepted for determine compliance in other programs or rules (i.e. Part 60, 45 CSR §10A-6.1.b.1.) Thus, the CEMS monitoring requirement of Conditions A.9. and A.11. of R14-0027B will be incorporated into as Condition 4.2.3. and expanded to cover the all of the existing CEMS on all three units. Condition 4.5.3. outlines the submission of Compliance Reports on a semi-annual basis, which mirroring off of the reporting period in Title V and requirements of Rules 10 and 10A.

Section B of Permit R14-0027B contained specific applicable rule citations from 45 CSR 2, 45 CSR 10, 45 CSR 13, and 45 CSR14. For the most part these rule citations are no longer necessary due the new DAQ Permit Format. The citations from Rules 2 and 10 are incorporated as part of the specific conditions for PM and SO_2, expect for the opacity standard of 45 CSR§2-3.1. Condition 4.1.4. was created to incorporate the visible emission standard for the three boilers in the modified permit. The monitoring plan requirements of Rule 2 of 45 CSR §2-8.2.(a) was incorporated in in Condition 4.2.3., which contains the appliance's approved monitoring plan for Rule 2.

No. 6 Boiler is currently covered by Permit R13-1637A. The proposed modification application request to consolidate Permit R13-1637A, which makes sense that that the facility's boilers will be covered under one permit. This permit set emissions, fuel, and heat input limits for this unit. Only Condition 4.1.3. was incorporated as stated in Permit R13-1673A in the proposed permit. Permit R13-1637A relied on fuel monitoring. This fuel monitoring requirement was incorporated into Condition 4.4.4. as a fuel tracking requirement for all of the boilers covered by the permit. Condition 4.1.3. was the federally enforceable limit that allowed the boiler not to be subject to NOx limit under Subpart Db. Due to the long lead time for this particular project, over 18 months away, the writer felt it was necessary to retain this as a transition condition or the source would be require to install NO_x CEMs after issuance.

The rest of the specific conditions from Permit R13-1637A were replace in the proposed draft, which mainly focus on CO and NO_x emissions with an annual ceiling limit on heat input. While operating during the transition period, CO emission should be relative minimal and NO_x emissions should be less than the newly establish limit in the permit. So, the unit should be capable of complying with the emission limits in the proposed draft. As noted earlier in this evaluation, the heat input limit is the preferred choice than set a total fuel limit or individual fuel by type.

Permit R13-1637A has general language for the unit to comply with the Boiler MACT. This condition will be replaced with the applicable specific requirements and compliance schedule for these units. Both units will be re-equipped with oxygen trim system, and therefore there is condition requiring such combustion controls. This allow for the timing of the subsequent tune-up for each unit to be once every five years. Another condition was established that require the applicant to conduct the one-time energy assessment.

The specific requirements for No. 6 Boiler has a mercury concentration limit for the hydrogen fuel and required to develop a site specific fuel analysis plan to demonstrate compliance with the fuel restriction.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates the proposed modification of the Nos. 5 and 6 Boilers will meet all the requirements of the application rules and regulations when operated in accordance to the permit application. By granting the MACT Extension Request makes this proposed scheduling of this modification to be acceptable. Once completion of this project is complete, this modification will reduce the potential to emit of nearly 6,500 tons per year of sulfur dioxide and 2,400 tons per year of oxides of nitrogen without the use of add on controls, which are pollutants that Marshall County has had issue maintaining within acceptable levels. Therefore, this writer recommends combining Permits R13-1637A and R14-0027B and granting Eagle Natrium a Rule 13 modification permit for their Natrium Plant located near New Martinsville, WV.

Edward S. Andrews, P.E.
Engineer

May 12, 2014
Date

West Virginia Department of Environmental Protection

Earl Ray Tomblin
Governor

Division of Air Quality

Randy C. Huffman
Cabinet Secretary

Permit to Modify

R14-0027D

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:
Eagle Natrium LLC
Natrium Plant/New Martinsville
051-00002

William F. Durham
Director

Issued: July 1, 2014

This permit will supercede and replace Permit R14-0027B and Permit R13-1637A.

Facility Location:	State Route 2 New Martinsville, Marshall County, West Virginia
Mailing Address:	Box 191 New Martinsville, WV 26155
Facility Description:	Chemical Manufacturing
NAICS Codes:	324181 & 325110
UTM Coordinates:	512.7 km Easting • 4,399.6 km Northing • Zone 17
Permit Type:	Modification
Description of Change:	This action is for the retrofit of Nos. 5 and 6 Boilers to natural gas which will result in the shutdown of Nos. 3 and 4 Boilers.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Table of Contents

1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
R011	S076	No.3 Boiler (Unit to be shut down upon completion of conversion project)		243 MMBtu/hr	FF (FF001)
R015	S076	No. 4 Boiler (Unit to be shut down upon completion of conversion project)		496 MMBtu/hr	ESP (ES002)
R072	S482	No.5 Boiler (Being modified to fired only with natural gas)	1966/2016	878 (coal)/1,125 (NG) MMBtu/hr	ESP** (ES001)
R097	S076	No. 6 Boiler with Low-NO_x Burner (Being modified to fired either with 100% hydrogen or natural gas)	1993/2015	182 MMBTU	None

* - Boiler #5 will be retrofitted 9 burners. The 24-hour average design heat input will be 999 MMBtu/hr with the unit operating on 8 of the 9 burners in produce steam at its designed capacity.
* - Will not be used required to be operated once the unit becomes a natural gas only (Gas 1) burning unit.
FF – Fabric Filter Baghouse
ESP – Electrostatic Precipitator

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.1.4. Unless otherwise specified in a permit condition or underlying rule or regulation, all references to "rolling yearly total" shall mean the sum of the monthly data, values or parameters being measured, monitored, or recorded, at any given time for the previous twelve (12) consecutive calendar months.

2.2. Acronyms

CAAA	Clean Air Act Amendments	**NO_X**	Nitrogen Oxides
CBI	Confidential Business Information	**NSPS**	New Source Performance Standards
CEM	Continuous Emission Monitor	**PM**	Particulate Matter
CES	Certified Emission Statement	**$PM_{2.5}$**	Particulate Matter less than 2.5 µm in diameter
C.F.R. *or* **CFR**	Code of Federal Regulations	**PM_{10}**	Particulate Matter less than 10µm in diameter
CO	Carbon Monoxide	**Ppb**	Pounds per Batch
C.S.R. *or* **CSR**	Codes of State Rules	**Pph**	Pounds per Hour
DAQ	Division of Air Quality	**Ppm**	Parts per Million
DEP	Department of Environmental Protection	**Ppm_V or ppmv**	Parts per Million by Volume
dscm	Dry Standard Cubic Meter	**PSD**	Prevention of Significant Deterioration
FOIA	Freedom of Information Act	**Psi**	Pounds per Square Inch
HAP	Hazardous Air Pollutant	**SIC**	Standard Industrial Classification
HON	Hazardous Organic NESHAP	**SIP**	State Implementation Plan
HP	Horsepower	**SO_2**	Sulfur Dioxide
lbs/hr	Pounds per Hour	**TAP**	Toxic Air Pollutant
LDAR	Leak Detection and Repair	**TPY**	Tons per Year
M	Thousand	**TRS**	Total Reduced Sulfur
MACT	Maximum Achievable Control Technology	**TSP**	Total Suspended Particulate
MDHI	Maximum Design Heat Input	**USEPA**	United States Environmental Protection Agency
MM	Million	**UTM**	Universal Transverse Mercator
MMBtu/hr *or* **mmbtu/hr**	Million British Thermal Units per Hour	**VEE**	Visual Emissions Evaluation
MMCF/hr *or* **mmcf/hr**	Million Cubic Feet per Hour	**VOC**	Volatile Organic Compounds
NA	Not Applicable	**VOL**	Volatile Organic Liquids
NAAQS	National Ambient Air Quality Standards		

NESHAPS National Emissions Standards for Hazardous Air Pollutants

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*;

2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration;*

2.3.3. 45CSR19 – *Requirements for Pre-Construction Review, Determination of Emission Offsets for Proposed New or Modified Stationary Sources of Air Pollution and Emission Trading for Intrasource Pollutants.*

2.4. Term and Renewal

2.4.1. This permit supersedes and replaces previously issued Permit R14-0027B and Permit R13-1637A. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-1637, R13-1637A, R14-0027, R14-0027A, R14-0027B, R14-0027C, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.11 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements
[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

   1. The permit or rule evaluated, with the citation number and language;
   2. The result of the test for each permit or rule condition; and,
   3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class with postage prepaid to the address(es) set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

If to the DAQ:
Director
WVDEP
Division of Air Quality
601 57th Street
Charleston, WV 25304-2345

If to the US EPA:
Associate Director
Office of Air Enforcement and Compliance Assistance
(3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

3.5.4. Operating Fee

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements

4.1. Limitations and Standards

4.1.1. The following conditions and requirements are specific to No. 3 Boiler (ID # R011) until 180 days after the restart of Nos. 5 & 6 Boilers from completion the natural gas conversion project:

a. Emissions from No. 3 Boiler shall not exceed the following:

i. The boiler shall not discharge NO_x emissions in excess of 0.75 lb/MMBtu heat input on a daily average basis. This limit applies at all times, including periods of startup, shut down, or malfunctions.

ii. The boiler shall not discharge PM emissions in excess of 10.27 lb per hour.
[45 CSR §2-4.1.b.]

iii. The boiler shall not discharge SO_2 emissions in excess of 750 lb per hour on a continuous twenty-four hour average basis. A continuous twenty-four (24) period is defined as one (1) calendar day. This limit applies at all times, including periods of startup, shut down, or malfunctions.
[45 CSR §§10-3.1.e. and 3.8.]

4.1.2. The following conditions and requirements are specific to No. 4 Boiler (ID # R015)) until 180 days after the restart of Nos. 5 & 6 Boilers from completion the natural gas conversion project:

a. Emissions from No. 4 Boiler shall not exceed the following:

i. The boiler shall not discharge SO_2 emissions in excess of 1,538 lb per hour on a continuous twenty-four hour average basis. A continuous twenty-four (24) period is defined as one (1) calendar day. This limit applies at all times, including periods of startup, shut down, or malfunctions.
[45 CSR §§10-3.1.e. and 3.8]

ii. The boiler shall not discharge PM emissions in excess of 44.6 lb per hour.
[45 CSR §2-4.1.b.]

4.1.3. The following conditions and requirements are specific to No. 5 Boiler (ID #R072):

a. Emissions from the boiler prior to the converting the unit to natural gas shall not exceed the following:

i. The boiler shall not discharge SO_2 emissions in excess of 1,479 lb per hour on a continuous twenty-four hour average basis. A continuous twenty-four (24) period is defined as one (1) calendar day. This limit applies at all times, including periods of startup, shut down, or malfunctions.
[45 CSR §§10-3.1.e. and 3.8]

ii. The boiler shall not discharge PM emissions in excess of 79 lb per hour.
[45 CSR §2-4.1.b.]

b. After the boiler has been converted to natural gas firing, the emission limits in this item are in effect upon the initial restarting from being converted to fire on natural gas. The boiler shall not exceed the following limitations:

i. CO emissions emitted to the atmosphere from the boiler shall not exceed 0.082 pounds per MMBtu. A new 30-day rolling average emission rate shall be determined on a daily basis and shall be calculated as the average of all the hourly CO emission data for the preceding 30 steam generating unit operating days.

ii. NO_x emissions emitted to the atmosphere from the boiler shall not exceed 0.16 pounds per MMBtu. A new 30-day rolling average emission rate shall be determined on a daily basis and shall be calculated as the average of all the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

iii. The boiler shall only be fired with "pipeline quality natural gas" as defined in 45 CSR§10A-2.7. Compliance with this condition satisfies compliance with the limitations of 45CSR§2-3.1., 45CSR§2-4.1.b., 45CSR§10-3.1.e.; and the requirement of 45 CSR §2-8.1.a., 45 CSR §2-8.2., and Section 8 of 45 CSR §10.
[45 CSR §2-8.4.b., 45 CSR §2A-3.1.a., 45 CSR §10-10.3., and 45CSR §10A-3.1b.]

iv. The 24- hour average heat input of the boiler shall be no greater than 999 MMBtu/hr. Compliance with this limit for the boiler shall be satisfied by limiting the annual total heat input into the unit to 8,751,240 MMBtu on 12 month rolling total basis.

4.1.4. The following conditions and requirements are specific to No. 6 Boiler (ID #R097):

a. CO emissions emitted to the atmosphere from the boiler shall not exceed 0.085 pounds per MMBtu. A new 30-day rolling average emission rate shall be determined on a daily basis and shall be calculated as the average of all the hourly CO emission data for the preceding 30 steam generating unit operating days.

b. NO_x emissions emitted to the atmosphere from the boiler shall not exceed 0.04 pounds per MMBtu. A new 30-day rolling average emission rate shall be determined on a daily basis and shall be calculated as the average of all the hourly NO_x emission data for the preceding 30 steam generating unit operating days.
[40 CFR §60.44b(a), (h), and (i)]

c. The boiler shall only be fired with hydrogen gas, pipeline quality natural gas or any combination of these two fuels. Compliance with this condition satisfies compliance with the limitations of 45CSR§2-3.1., 45CSR§2-4.1.b., 45CSR§10-3.1.e.; and the requirement of 45 CSR §2-8.1.a., 45 CSR §2-8.2., and Section 8 of 45 CSR §10.
[45 CSR §2-8.4.b., 45 CSR §2A-3.1.a., 45 CSR §10-10.3., and 45CSR §10A-3.1b.]

d. The hydrogen gas to be fired in the boiler shall not have a concentration of greater than 40 micrograms of mercury per cubic meters of gas after January 31, 2016. The hydrogen gas meeting this standard is classified as an "other gas 1 fuel" under Subpart DDDDDD of Part 63.
[40 CFR §63.7575]

e. The 24-hour average heat input of boiler shall be no greater than 182 MMBtu/hr. Compliance with this limit for the boiler shall be satisfied by limiting the annual total heat input into the unit by 1,594,320 MMBtu on 12 month rolling total basis.

f. Natural gas, with an average rating of 906 BTUs per cubic foot, shall be available as a secondary fuel to the boiler for start-up and stabilization procedures during routine boiler operation. Natural gas consumption shall not exceed a maximum of 15,080 cubic feet per hour and 132.1 x 10^6 cubic feet per year.
[40 CFR §60.44(e)]

g. Prior to the conversion, item f of this condition shall be in effect. Upon initial re-start of the unit from conversion modification, item f of this condition is no longer applicable or enforceable.

4.1.5. Visible emissions from each of these emission points S076 (Nos. 3, 4, & 6 Boilers Stack), and S482 (No. 5 Boiler) shall not be greater than ten (10) percent opacity based on a six minute block average.
[45 CSR §2-3.1]

4.1.6. Nos. 5 and 6 Boilers shall be equipped, maintained, operated with an oxygen trim system that maintains an optimum air to fuel ratio for each unit. Such system shall be installed up on initial start-up of the unit from the conversion to natural gas retrofit.
[40 CFR §63.7575]

4.1.7. Once the natural gas conversion for Nos. 5 and 6 Boilers has been completed individually, the initial tune-up and subsequent tune-ups for the units shall be conducted in accordance with the following timing and tune-up requirements:

a. If the initial start-up after the conversion occurs before January 31, 2016, then the initial tune-up for the unit must be completed by no later than January 31, 2016.
[40 CFR §63.7510(e) & §63.7495(b)]

b. If the initial start-up after the conversion occurs after January 31, 2016, then the initial tune-up for the unit shall be completed by no later than 30 calendar days after the initial start-up from the natural gas conversion of the unit.
[40 CFR §63.7510(j)]

c. Subsequent tune-ups shall be completed no later than 61 months after previous tune-up.
[40 CFR §63.7515(d) § 63.7540(a)(12)]

d. Each tune-up shall consist of the following:

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (permittee may delay the burner inspection until the next scheduled unit shutdown). 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);

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, which includes the manufacturer's NOx concentration specification taken inconsideration; and

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.

[40 CFR §63.7500(a)(1), §63.7505(a), §63.7515(d), §§63.7540(a)(10) & (12), and Table 3 to Subpart DDDDD of Part 63—Work Practice Standards]

4.1.8. The permittee shall conduct a "one-time energy assessment" of the facility, which must include Nos. 5 and 6 Boilers, as specified in Table 3 of 40 CFR 63 Subpart DDDDD. Pursuant to 40 CFR §63.7510(e), the energy assessment shall be completed no later than January 31, 2016.
[40 CFR §63.7500(a)(1), §63.7505(a), and Table 3 of 40 CFR 63 Subpart DDDDD]

4.1.9. As requested by the permittee on March 19, 2014, the Director hereby grants the permittee an extension for compliance with the HAP emission limitations of Subpart DDDDD of Part 63 of Chapter 40 for Nos. 3, 4, and 5 Boilers in accordance with the following limitations.

No. 5 Boiler may be operated as currently configured burning coal until March 1, 2016.

No 3. and No.4 Boilers may be operated as currently configured burning coal until December 1, 2016 or 180 days after the restart of No. 5 Boiler as a "Gas 1 Unit", whichever is sooner. Afterward, No. 3 and No. 4 Boilers shall be permanently shut down.

In effort to minimize HAP emissions during the extension, the permittee shall at the minimum implement the following work practices to these units on or before January 31, 2016:

a. Conduct a tune-up on each unit in accordance with the tune-up requirement of Condition 4.1.7., which include associated records.

b. The units shall be limited to using natural gas fuel during start-up operations.

c. Once the unit starts firing pulverized coal, the permittee must begin to operate associated particulate matter control for the unit as expeditiously as possible.

d. The permittee must operate the associated particulate matter control at all times when the unit is operating.

e. The permittee shall operate and maintain the oxygen trim system on each unit.

f. During shut down of the unit, the permittee must continue to operate the associated particulate matter control device.

g. The permittee must operate the units in accordance with the other applicable limits in this permit.

The permittee shall maintain records of implementing these work practices in accordance with Condition 3.4.1. and following the reporting requirements of Condition 4.5.5.
[40 CFR §63.6(i) and 45 CSR §14-2.46.h.]

4.1.10. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.11.]

4.2. Monitoring Requirements

4.2.1. For No. 3, No. 4, and No. 5 Boilers while operating on coal or combination of coal, the permittee shall operate and maintain a continuous emission monitoring system (CEMS) for measuring SO_2, NO_2, carbon dioxide (CO_2) as a diluent, and exhaust flow measuring device from each boiler.

The SO2 CEMS for Boilers No. 3, 4, and 5 shall be installed, certified, operated, and maintained as specified in 40 C.F.R. Part 60, Appendix B, Performance Specification 2 (PS2) and shall follow the quality assurance requirements set forth in 40 CFR Part 60, Appendix F.

The NO_x, diluent gas, and the flow monitoring systems for Boilers No. 3 4, and 5 shall be installed, certified, operated, maintained in accordance with the quality assurance procedures as specified in 40 CFR Subpart C of Part 75.

The permittee must calculate and record an hourly average or heat input average (respective to the terms of the emission limit for the corresponding pollutant) emission rate on a daily basis for each pollutant identified in this condition for each boiler. CEMS unit conforming to the specifications of 40 CFR Part 75 shall use unbiased, un-substituted data to demonstrate compliance with the limits as specified in this permit.

Records of all data collected, calibrations, calibration checks, maintenance preformed, and malfunctions of the CEMS shall be maintained in accordance with Condition 3.4.1. of this permit. The use of SO_2 CEMS satisfy the requirement of a monitoring plan pursuant to 45 CSR §10-8.2.c. **[45 CSR §10-8.2.c, and 45 CSR §10A-6.1.b.]**

4.2.2. For the purpose of satisfying the monitoring plan requirements of 45 CSR 2, the permittee shall conduct the following monitoring with respect to each unit and associated PM control device:

a. Conduct either Method 22 or Method 9 as outlined in Appendix A of 40 CFR Part 60, observation once per month for the purpose of verifying or demonstration compliance with the standard in Condition 4.1.4. for the respective emission point. If visible emissions are detected using a Method 22, a Method 9 must be conduct to determine compliance with the actual standard within seven operating days of the Method 22 observation.

b. The permittee shall monitor the number of fabric filter compartments online for the fabric filter baghouse (FF0001) and the number of modules on the precipitator T/R Cabinets that are in service for each ESP (ES001 & ES002). The permittee shall make record of the date and time of the changes to the compartments or modules in service and the respective change. For proper operation of the fabric filter baghouse FF001, 5 of the 8 compartment must be in service at all times. For proper operation of the ESP ES001, 6 of the 16 modules must be in service at all times. For proper operation of the ESP ES002, 4 of the 11 modules must be in service at all times.

c. For fabric filter bag house FF001 only, the service "status" of each compartment will be monitored on a continuous display panel and the differential pressure across the compartment (recorded every two hours) will be used to determine the status.

d. For ESPs ES001 and ES002 only, the primary AC voltage on the T/R Cabinets is displayed in the operations control room, and this value is recorded once per shift. A voltage reading greater than 0 indicates the modules in that T/R Cabinet are in service.

e. In the event of an excursion and if practicable, the permittee shall isolated and repair the fabric filter compartment or ESP module. In the event that the number of compartments or modules in service are below the minimum number as list in item b. for the respective control device, the permittee shall conduct a Method 9 observation to determine compliance with the standard in Condition 4.1.5. If the initial observation determines an excursion of the standard, the permittee shall continue to conduct Method 9 observations for each hour during the excursion until four (4) successive six minute observations demonstrated compliance with the standard.

All records of the monitoring and actions taken shall be maintained in accordance with Condition 3.4.1. Once the natural gas conversion of No.5 Boiler is completed and No. 3. and No.4 Boilers are shut-down , the monitoring requirement of this condition is no longer required per 45 CSR §2A-3.1.b.
[45 CSR §§2-8.2 and 8.3]

4.2.3. For No. 5 Boiler post conversion to natural gas, the permittee shall install, operate, certify and maintain a continuous emission monitoring system (CEMS) for measuring NO_x, CO, and diluent gas (CO_2 or O_2) monitoring system from the exhaust of No. 5 Boiler in accordance with the applicable Performance Specifications under Appendix B to Part 60 of Chapter 40 for CO and Part 75 of Chapter 40 for NO_x, and diluent gas. Such monitor system shall include an automated data acquisition and handling system (DAHS). All required certification tests of the monitoring system must be completed no later than 90 unit operating days or 180 calendar days (whichever is sooner) after initial start-up from the natural gas conversion project.

The permittee may elect to use a predictive emission monitoring system (PEMS) as an alternative monitoring system in lieu of CEMS. Using PEMS, the permittee must have this alternative monitoring system certified under the applicable procedures of Subpart E of 40 CFR 75 and approved by the USEPA Administrator.

The permittee must calculate and record an hourly average or heat input average (respective to the terms of the emission limit for the corresponding pollutant) emission rate on a daily basis for each pollutant identified in this condition for each boiler. CEMS unit conforming to the specifications of 40 CFR Part 75 shall use unbiased, un-substituted data to demonstrate compliance with the limits as specified in this permit.

For purposes of calculating data averages, the permittee cannot use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities. The permittee must use all the data collected during all other periods in assessing compliance with the emission limit permitted in Condition 4.1.3. Any periods for which the monitoring system is out of control and data are not available for required calculations constitute a deviation from the monitoring requirements. Records of all data collected, calibrations, calibration checks, relative accuracy tests, maintenance preformed, and malfunctions of the CEMS/PEMS shall be maintained in accordance with Condition 3.4.1. of this permit.
[45 CSR §40-71. and 40 CFR §75.20. (NOx Monitoring)]

4.2.4. For No. 6 Boiler post conversion to natural gas, the permittee shall install, operate, certify and maintain a continuous emission monitoring system (CEMS) for measuring NO_x, CO, and either CO_2 or oxygen analyzer according to the applicable procedures under Appendix B, and Appendix F to Part 60 of Chapter 40 on a continuous basis. Such monitor system shall include an automated data acquisition and handling system (DAHS).

The span value for the NO_x CEMs shall be 500 ppm (40 CFR §60.48b(e)(2)(i)) if applicable.

The permittee must conduct and pass a performance evaluation of the CEMS or PEMS according to the procedures under 40 CFR §60.13. within 180 days after restarting of the boiler.

For NO_x and CO_2 or O_2 direct measurement only; when NO_x emission data are not obtained because of CEMS breakdown, repairs, calibration checks, and zero and span adjustment, emission data will be obtained by using standby monitoring systems, Method 7 or 7A of Appendix A of Part 60, or other approved reference methods to provided emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of the 30 successive steam generating unit operating days. **[40 CFR §60.48b(f)]**

The permittee may elect to use a predictive emission monitoring system (PEMS) as an alternative monitoring system in lieu of CEMS. Such PEMS must meet the Performance Specification (PS) 16 of Appendix B-Performance Specifications and Appendix F-Quality Assurance Procedures to Part 60, which consist of passing an initial and follow-up relative accuracy test, and conducting periodic quality assurance (QA) assessments. Using PEMS, the permittee must submit an application request and obtain approval by the USEPA. Administrator in accordance with 40 CFR §60.13(i) and the most current version of Emissions Measurement Center Guideline Document EMC GD-022 before using the NO_x PEMS for demonstrating compliance with 40 CFR §60.44b.

For purposes of calculating data averages, the permittee cannot use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities. The permittee must use all the data collected during all other periods in assessing compliance with the emission limit permitted in Condition 4.1.4. Any periods for which the monitoring system is out of control and data are not available for required calculations constitute a deviation from the monitoring requirements. Records of all data collected, calibrations, calibration checks, relative accuracy tests, maintenance preformed, and malfunctions of the CEMS/PEMS shall be maintained in accordance with Condition 3.4.1. of this permit.
[40 CFR §§60.48b(b) though (f) and 45 CSR 13-5.11]

4.3. Testing Requirements

4.3.1. The permittee shall conduct testing for demonstrating compliance with the PM limits of Conditions 4.1.1.a.ii., 4.1.2.a.ii., and 4.1.3.a.ii. in accordance with 45 CSR §2A-5.2.a. and Condition 3.3.1. In conjunction with this PM demonstration, the permittee shall demonstrate compliance with the visible emission standards of Condition 4.1.4 using Method 9 with respect to the unit being tested. The determination of the timing shall be based on the weight allowable for each unit established by 45 CSR §2-4.1.b. in accordance with frequency prescribed in §2A-5.2.a. Records of such testing shall be maintained in accordance with Condition 3.4.1. of this permit.

Once the natural gas conversion of No.5 Boiler is complete, the periodical testing requirement of this condition is no longer required per 45 CSR §2A-3.1.b.
[45 CSR §2-8.1., 45CSR §§2A-5.1.a and 5.2.a.]

4.3.2. The permittee shall determine if the hydrogen gas produced at the facility meets the specification as stated in Condition 4.1.4.e. by using the approved site-specific fuel analysis plan for sampling and analyzing the hydrogen gas that is to be used as fuel in No. 6 Boiler no later than July 31, 2016.
[40 CFR §63.7510(e)]

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. The permittee shall keep records of fuel consumed by each boiler on a daily basis, which includes coal and natural gas usage. The permittee shall obtain an ash and Btu analysis for each shipment of coal to the facility. For the purpose of demonstrating that the natural gas has insignificant amount of sulfur, the permittee shall keep fuel receipts (such as a, valid purchase contract, tariff sheet, or transportation contact) from the natural gas supplier.

Once the natural gas conversion for No. 6 Boiler has been completed, the permittee shall calculate the annual capacity factor for natural gas. 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. Such records shall be maintained in accordance with Condition 3.4.1.
[45CSR §2-7.1.a.6., and 45 CSR §10-8.3.c.][No. 6 Boiler only – 40 CFR §§60.49b(d)(2), (r)(1)]

4.4.5. The permittee shall maintain records of the monitoring as required in Conditions 4.2.3. and 4.2.4. for each steam generating unit operating day, which at least the following information:

a. Calendar date;

b. The average hourly NO_x and CO emission rate in terms of lb per MMBtu heat input;

c. The 30 day average NO_x and CO emission rates calculated at the end of each steam generating unit operating day for the preceding 30 steam generating unit operating days;

d. Identification of steam generating unit operating days when the calculated 30 day average NO_x or CO emission rates are in excess of the respective limits in Conditions 4.1.3. and 4.1.4. with reasons for such excess emissions and description of corrective actions taken;

e. Identification of the steam generating unit operating days for which pollutant data have not been obtained, include reasons for not obtaining sufficient data and a description of corrective actions taken;

f. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

g. Identification of the times when the pollutant concentration exceeded full span of the CEMS;

h. Description of any modifications to the CEMS or PEMS that could affect the ability of the CEMS or PEMS to comply with respective PS; and

i. Results of daily CEMS drift tests and quarterly accuracy assessments as required Appendix F, Procedure 1 or Part 75.

4.5. Reporting Requirements

4.5.1. The permittee shall submit to the Director within 45 days of completion of performance evaluation for the CEMS or PEMS for No. 5 Boiler two copies of the performance evaluation report of CEMS or PEMS for each unit and a copy of the Re-Certification Application.
[40 CSR §40-74.3. and 40 CFR §75.63.]

4.5.2 The permittee shall submit to the Director within 60 days of completion of performance evaluation for the CEMS or PEMS for No. 6 Boiler two copies of the performance evaluation report of CEMS or PEMS.
[40 CFR §60.13(c)(1)]

4.5.3. Once the CEMS or PEMS for No. 5 and No. 6 Boilers has been certified after being converted to natural gas; *Semi-Annual CO and NO_x Excess Emission and Monitoring System Performance Report:* To be included with the facility's Annual and Semi-Annual Title V Compliance Report, the permittee shall submit a report to the Director summarizing CO and NO_x emissions including periods of startups, shutdowns, malfunctions, and CEMS or PEMS system monitor availability for the reporting period. The reporting period is January 1st to June 30th and July 1st to December 31st. Such report shall contain the information collected during the respective reporting period as required in Condition 4.4.5. Any emissions data that indicates that the limits as stated in Section 4.1. were exceeded during the corresponding reporting period must be noted in this summary report. At the minimum, the date and time, length of the exceedances(s), magnitude, percentage of excess emissions, the limit that was exceeded, the cause of the exceedances, and the corrective action taken shall be included in the summary report. Submittal of 40 CFR 75 data (NO_x) in electronic data reporting (EDR or XML) format to the Administrator shall be deemed to satisfy the

reporting requirements of this condition for NO_x emissions from No. 5 Boiler, expect that excess NOx emission from No. 5 Boiler shall be included in this report.
[40 CFR §60.7(c); 40 CFR §§60.49b(h) and (2)(ii); and 45CSR§13-3]

4.5.4. The permittee shall develop and submit a site-specific fuel analysis plan for the hydrogen fuel for determining if it is meets the specification in Condition 4.1.4.e. Such plan must follow or conform to the procedures and requirements in 40 CFR §§63.7521(g)(1), (2), and item 3 of Table 6 to Subpart DDDDD of Part 63 to the Director by no later than July 31, 2015.
[40 CFR §63.7521(g)]

4.5.5. The permittee shall submit a "Notification of Compliance Status" to the Director before the close of business on the sixtieth (60^{th}) day after completion of the initial compliance demonstration as required in 40 CFR §63.7530(e) and (g). Such "Notification of Compliance Status" shall be in accordance with 40 CFR §63.9(h)(2(ii) and contain the information specified in 40 CFR §§63.7545(e)(1), (2), (6), (7) and (8), which included a statement the one time energy assessment was completed as required in Condition 4.1.7., the initial tune-up for each unit was completed and the initial fuel analysis was conducted according to §63.7525 for the hydrogen gas and meet the specifications as an "other gas (1) fuel" (Condition 4.1.4.e.).
[40CFR§63.7545(e), §63.7530(e) and (g)]

4.5.6. The permittee shall submit "5 year Compliance Report" to the Director for No. 5 and No. 6 Boilers with the first report being submitted by no later than January 31, 2016, or the first January 31 following the initial tune-up of the unit, and subsequent reports are due every 5 years from thereafter. Such reports shall contain the information specified in 40 CFR §§63.7550(c)(5)(i) through (iv) and (xiv) which are:

a. Permittee and facility name, and address;

b. Process unit information, emission limitations, and operating limitations;

c. Date of report and beginning and ending dates of the reporting period;

d. The total operating time during the reporting period of each affected unit;

e. Include the date of the most recent tune-up for the boiler; and

f. Include the date of the most recent burner inspection if it was not done within 5 year tune-up and was delayed until the next scheduled or unscheduled unit shutdown.

[40CFR §§63.7550(b), (b)(1), (c)(1), & (c)(5)(i) though (iv) and (xiv)]

4.5.7. The permittee shall report the following milestones as part of extension in Condition 4.1.8. to the Director in writing within 15 days of meeting the each of the following:

a. Completion of the tune-ups for No. 3, No. 4, and No. 5 Boilers;

b. Receipt of delivery of all major components for the conversion outage;

c. The data of that No.5 Boiler shut-down for the conversion outage;

d. The restart date of No. 5 Boiler as a "Gas 1 Unit"

e. The shut-down date of No. 3 Boiler;

f. The shut-down date of No. 4 Boiler.

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ______________________, representing the period beginning ______________ and ending ______________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ________________________________ ______________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title ______________________ ______________________
(please print or type) Name Title

Telephone No. ______________________ Fax No. ______________________

1 This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

   (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

   (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of USEPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.