[External] ACE Application

Wednesday, June 3, 2020 10:10 AM

Subject	**[External] ACE Application**
From	Stephen Nelson
To	Crowder, Laura M
Cc	Caperton, Austin; Andrews, Edward S; Abraham, Brian R; Jeff Keffer; Chris Hamilton; Thomas T. Lampman
Sent	Monday, June 1, 2020 12:53 PM
Attachments	Executed Application June 1 Cover Letter

CAUTION: External email. Do not click links or open attachments unless you verify sender.

Laura,

Attached is Longview's application for the Affordable Clean Energy rule. We have arranged for the original and three copies to be hand delivered to you today. Longview recognizes that this application is for a new rule and some questions and details may need to be discussed. We are looking forward to assisting and clarifying any technical or compliance issues as they may arise. We are looking forward to working with you and your staff.

Best Regards –

Stephen Nelson - Chief Operating Officer
Snelson@Longviewpower.net I Cell: 304 282 5059

LongviewPower

Office: 304-599-0930 Ext:3054 | Fax: 304-599-3829

1375 Fort Martin Rd Maidsville, WV 26541

http://www.LongviewPower.com

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Hardcopy of June 1 Submittal

Thursday, June 11, 2020 3:27 PM

LONGVIEW POWER LLC

A New Generation of Power

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WV DEP / DIV OF AIR QUALITY

June 1, 2020

Ms. Laura Crowder, Director
WVDEP - Division of Air Quality
601 57th Street
Charleston, WV 25304

Re: Request for Administrative Amendment
Permits R14-0024G and R30-06100134-2018
Longview Power Plant
DAQ Facility ID 0061-00134
Maidsville, Monongalia County, WV

Dear Ms. Crowder:

This letter follows the recent conversations regarding the WVDEP implementation of 40 CFR Part 60, subpart UUUUa, commonly referred to as the Affordable Clean Energy (ACE) Rule, 40 CFR Part 60, subpart Ba, and subsequent development of 45CSR44. In response to the promulgation of these rules, Longview Power is requesting an amendment to existing permits R14-0024G and R30-06100134-2018 to include the Carbon Dioxide (CO_2) Standard of Performance, and associated program requirements. Attached please find the support documentation for this request.

If you have any questions, please contact me, at (304) 282-5059 or snelson@longviewpower.net.

Sincerely,

Stephen Nelson
Chief Operating Officer – Longview Power, LLC

cc:

Secretary Austin Caperton	WV Department of Environmental Protection
Scott Mandirola, Deputy Secretary	WV Department of Environmental Protection
Edward Andrews, Engineer	WV Department of Environmental Protection
Anne Idsal, Principal Deputy Asst.	USEPA Headquarters Administrator
Karl Moore, Deputy Chief Administrator	USEPA Headquarters
Cosmo Servidio, Regional Administrator	Environmental Protection Agency, Region 3
Brian Abraham, General Counsel	Office of the Governor, West Virginia
Thomas Lampman, Assist. Solicitor	Office of the WV Attorney General

1375 Fort Martin Road, Maidsville, WV 26541
Phone: 304-599-0930 Fax: 304-599-3829

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION **DIVISION OF AIR QUALITY** 601 57th Street, SE Charleston, WV 25304 (304) 926-0475 www.dep.wv.gov/daq	***APPLICATION FOR NSR PERMIT*** ***AND*** ***TITLE V PERMIT REVISION*** ***(OPTIONAL)***
PLEASE CHECK ALL THAT APPLY TO **NSR (45CSR13)** (IF KNOWN): ☐ **CONSTRUCTION** ☐ **MODIFICATION** ☐ **RELOCATION** ☐ **CLASS I ADMINISTRATIVE UPDATE** ☐ **TEMPORARY** ☐ **CLASS II ADMINISTRATIVE UPDATE** ☐ **AFTER-THE-FACT**	PLEASE CHECK TYPE OF **45CSR30 (TITLE V)** REVISION (IF ANY): ☐ **ADMINISTRATIVE AMENDMENT** ☐ **MINOR MODIFICATION** ☐ **SIGNIFICANT MODIFICATION** IF ANY BOX ABOVE IS CHECKED, INCLUDE TITLE V REVISION INFORMATION AS **ATTACHMENT S** TO THIS APPLICATION

FOR TITLE V FACILITIES ONLY: Please refer to "Title V Revision Guidance" in order to determine your Title V Revision options (Appendix A, "Title V Permit Revision Flowchart") and ability to operate with the changes requested in this Permit Application.

Section I. General

1. Name of applicant *(as registered with the WV Secretary of State's Office):* *Longview Power, LLC*	2. Federal Employer ID No. ***(FEIN):*** *04-3561860*
3. Name of facility *(if different from above):*	4. The applicant is the: ☐ **OWNER** ☐ **OPERATOR** ☒ **BOTH**
5A. Applicant's mailing address: 1375 Fort Martin Rd. Maidsville, WV 26541	5B. Facility's present physical address: 1375 Fort Martin Rd. Maidsville, WV 26541

6. **West Virginia Business Registration.** Is the applicant a resident of the State of West Virginia? ☐ **YES** ☒ **NO**

— If **YES,** provide a copy of the **Certificate of Incorporation/Organization/Limited Partnership** (one page) including any name change amendments or other Business Registration Certificate as **Attachment A.**

— If **NO,** provide a copy of the **Certificate of Authority/Authority of L.L.C./Registration** (one page) including any name change amendments or other Business Certificate as **Attachment A.**

7. If applicant is a subsidiary corporation, please provide the name of parent corporation:

8. Does the applicant own, lease, have an option to buy or otherwise have control of the *proposed site?* ☒ **YES** ☐ **NO**

— If **YES,** please explain: *Existing facility*

— If **NO,** you are not eligible for a permit for this source.

9. Type of plant or facility (stationary source) to be **constructed, modified, relocated, administratively updated** or **temporarily permitted** (e.g., coal preparation plant, primary crusher, etc.): *Coal-Fired EGU*	10. North American Industry Classification System **(NAICS)** code for the facility: *221112*
11A. DAQ Plant ID No. (for existing facilities only): *0061–00134*	11B. List all current 45CSR13 and 45CSR30 (Title V) permit numbers associated with this process (for existing facilities only): *R14-0024G, R30-06100134-2018, R33-56671-2023-3*

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

12A. — For **Modifications, Administrative Updates** or **Temporary permits** at an existing facility, please provide directions to the *present location* of the facility from the nearest state road; — For **Construction** or **Relocation permits,** please provide directions to the *proposed new site location* from the nearest state road. Include a **MAP** as **Attachment B**. *Longview Power facility is located on SR53, Fort Martin Rd. Physical address is 1375 Fort Martin Rd, Maidsville, WV 26541.*		
12.B. New site address (if applicable): *N/A*	12C. Nearest city or town:	12D. County:
12.E. UTM Northing (KM):	12F. UTM Easting (KM):	12G. UTM Zone:
13. Briefly describe the proposed change(s) at the facility: *Incorporation of 40 CFR Part 60, subpart UUUUa, and 45CSR44, ACE Rule Carbon Dioxide Standard of Performance into State (R14-0024G) and Federal (R30-06100134-2018) air permits.*		
14A. Provide the date of anticipated installation or change: *N/A* / / — If this is an **After-The-Fact** permit application, provide the date upon which the proposed change did happen: / /		14B. Date of anticipated Start-Up if a permit is granted: / /
14C. Provide a **Schedule** of the planned **Installation** of/**Change** to and **Start-Up** of each of the units proposed in this permit application as **Attachment C** (if more than one unit is involved). *N/A*		
15. Provide maximum projected **Operating Schedule** of activity/activities outlined in this application: ***24*** Hours Per Day ***7*** Days Per Week ***52*** Weeks Per Year		
16. Is demolition or physical renovation at an existing facility involved? ☐ **YES** ☒ **NO**		
17. **Risk Management Plans.** If this facility is subject to 112(r) of the 1990 CAAA, or will become subject due to proposed changes (for applicability help see www.epa.gov/ceppo), submit your **Risk Management Plan (RMP)** to U. S. EPA Region III.		
18. **Regulatory Discussion.** List all Federal and State air pollution control regulations that you believe are applicable to the proposed process *(if known)*. A list of possible applicable requirements is also included in Attachment S of this application (Title V Permit Revision Information). Discuss applicability and proposed demonstration(s) of compliance *(if known)*. Provide this information as **Attachment D.** ***Please see Attachment LVP-1***		

Section II. Additional attachments and supporting documents.

19. Include a check payable to WVDEP – Division of Air Quality with the appropriate **application fee** (per 45CSR22 and 45CSR13).
20. Include a **Table of Contents** as the first page of your application package. *N/A*
21. Provide a **Plot Plan,** e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is or is to be located as **Attachment E** (Refer to ***Plot Plan Guidance***). *N/A* - Indicate the location of the nearest occupied structure (e.g. church, school, business, residence).
22. Provide a **Detailed Process Flow Diagram(s)** showing each proposed or modified emissions unit, emission point and control device as **Attachment F.** *N/A*
23. Provide a **Process Description** as **Attachment G.** *N/A* — Also describe and quantify to the extent possible all changes made to the facility since the last permit review (if applicable).
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

24. Provide **Material Safety Data Sheets (MSDS)** for all materials processed, used or produced as **Attachment H.** - For chemical processes, provide a MSDS for each compound emitted to the air. *N/A*
25. Fill out the **Emission Units Table** and provide it as **Attachment I.** *N/A*
26. Fill out the **Emission Points Data Summary Sheet (Table 1 and Table 2)** and provide it as **Attachment J.** *N/A*
27. Fill out the **Fugitive Emissions Data Summary Sheet** and provide it as **Attachment K.** *N/A*
28. Check all applicable **Emissions Unit Data Sheets** listed below: *N/A* ☐ Bulk Liquid Transfer Operations ☐ Haul Road Emissions ☐ Quarry ☐ Chemical Processes ☐ Hot Mix Asphalt Plant ☐ Solid Materials Sizing, Handling and Storage Facilities ☐ Concrete Batch Plant ☐ Incinerator ☐ Storage Tanks ☐ Grey Iron and Steel Foundry ☐ Indirect Heat Exchanger ☐ General Emission Unit, specify Fill out and provide the **Emissions Unit Data Sheet(s)** as **Attachment L.**
29. Check all applicable **Air Pollution Control Device Sheets** listed below: *N/A*
☐ Absorption Systems ☐ Baghouse ☐ Flare ☐ Adsorption Systems ☐ Condenser ☐ Mechanical Collector ☐ Afterburner ☐ Electrostatic Precipitator ☐ Wet Collecting System
☐ Other Collectors, specify Fill out and provide the **Air Pollution Control Device Sheet(s)** as **Attachment M.**
30. Provide all **Supporting Emissions Calculations** as **Attachment N,** or attach the calculations directly to the forms listed in Items 28 through 31. *N/A*
31. **Monitoring, Recordkeeping, Reporting and Testing Plans.** Attach proposed monitoring, recordkeeping, reporting and testing plans in order to demonstrate compliance with the proposed emissions limits and operating parameters in this permit application. Provide this information as **Attachment O.** *N/A* Y Please be aware that all permits must be practically enforceable whether or not the applicant chooses to propose such measures. Additionally, the DAQ may not be able to accept all measures proposed by the applicant. If none of these plans are proposed by the applicant, DAQ will develop such plans and include them in the permit.
32. **Public Notice.** At the time that the application is submitted, place a **Class I Legal Advertisement** in a newspaper of general circulation in the area where the source is or will be located (See 45CSR§13-8.3 through 45CSR§13-8.5 and ***Example Legal Advertisement*** for details). Please submit the **Affidavit of Publication** as **Attachment P** immediately upon receipt. *N/A*
33. **Business Confidentiality Claims.** Does this application include confidential information (per 45CSR31)? ☒ **YES** ☐ **NO** Y If **YES,** identify each segment of information on each page that is submitted as confidential and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"Precautionary Notice – Claims of Confidentiality"*** guidance found in the ***General Instructions*** as **Attachment Q.** Attachment LVP-1

Section III. Certification of Information

34. **Authority/Delegation of Authority**. Only required when someone other than the responsible official signs the application. Check applicable **Authority Form** below: ☐ Authority of Corporation or Other Business Entity ☐ Authority of Partnership ☐ Authority of Governmental Agency ☐ Authority of Limited Partnership Submit completed and signed **Authority Form** as **Attachment R.**
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

35A. **Certification of Information.** To certify this permit application, a Responsible Official (per 45CSR§13-2.22 and 45CSR§30-2.28) or Authorized Representative shall check the appropriate box and sign below.

Certification of Truth, Accuracy, and Completeness

I, the undersigned ☑ **Responsible Official** / ☐ **Authorized Representative,** hereby certify that all information contained in this application and any supporting documents appended hereto, is true, accurate, and complete based on information and belief after reasonable inquiry I further agree to assume responsibility for the construction, modification and/or relocation and operation of the stationary source described herein in accordance with this application and any amendments thereto, as well as the Department of Environmental Protection, Division of Air Quality permit issued in accordance with this application, along with all applicable rules and regulations of the West Virginia Division of Air Quality and W.Va. Code § 22-5-1 et seq. (State Air Pollution Control Act). If the business or agency changes its Responsible Official or Authorized Representative, the Director of the Division of Air Quality will be notified in writing within 30 days of the official change.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

SIGNATURE _(Please use blue ink)_		DATE: 5-22-2020 _(Please use blue ink)_
35B. Printed name of signee: STEPHEN Nelson		35C. Title: COO
35D. E-mail: SNelson@LongViewpower.NET	36E. Phone: 304 282 5059	36F. FAX: 304-599 1673
36A. Printed name of contact person (if different from above):		36B. Title:
36C. E-mail:	36D. Phone:	36E. FAX:

PLEASE CHECK ALL APPLICABLE ATTACHMENTS INCLUDED WITH THIS PERMIT APPLICATION:

- ☐ **Attachment A: Business Certificate**
- ☐ **Attachment B: Map(s)**
- ☐ **Attachment C: Installation and Start Up Schedule**
- ☐ **Attachment D: Regulatory Discussion**
- ☐ **Attachment E: Plot Plan**
- ☐ **Attachment F: Detailed Process Flow Diagram(s)**
- ☐ **Attachment G: Process Description**
- ☐ **Attachment H: Material Safety Data Sheets (MSDS)**
- ☐ **Attachment I: Emission Units Table**
- ☐ **Attachment J: Emission Points Data Summary Sheet**
- ☐ **Attachment K: Fugitive Emissions Data Summary Sheet**
- ☐ **Attachment L: Emissions Unit Data Sheet(s)**
- ☐ **Attachment M: Air Pollution Control Device Sheet(s)**
- ☐ **Attachment N: Supporting Emissions Calculations**
- ☐ **Attachment O: Monitoring/Recordkeeping/Reporting/Testing Plans**
- ☐ **Attachment P: Public Notice**
- ☐ **Attachment Q: Business Confidential Claims**
- ☐ **Attachment R: Authority Forms**
- ☐ **Attachment S: Title V Permit Revision Information**
- ☐ **Application Fee**

Please mail an original and three (3) copies of the complete permit application with the signature(s) to the DAQ, Permitting Section, at the address listed on the first page of this application. Please DO NOT fax permit applications.

FOR AGENCY USE ONLY – IF THIS IS A TITLE V SOURCE:

- ☐ ***Forward 1 copy of the application to the Title V Permitting Group and:***
- ☐ ***For Title V Administrative Amendments:***
  - ☐ ***NSR permit writer should notify Title V permit writer of draft permit,***
- ☐ ***For Title V Minor Modifications:***
  - ☐ ***Title V permit writer should send appropriate notification to EPA and affected states within 5 days of receipt,***
  - ☐ ***NSR permit writer should notify Title V permit writer of draft permit.***
- ☐ ***For Title V Significant Modifications processed in parallel with NSR Permit revision:***
  - ☐ ***NSR permit writer should notify a Title V permit writer of draft permit,***
  - ☐ ***Public notice should reference both 45CSR13 and Title V permits,***
  - ☐ ***EPA has 45 day review period of a draft permit.***

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JUN 01 2020
WV DEP / DIV OF AIR QUALITY

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Attachment LVP-1a

Per W. Va. C.S.R. § 45-44-4, "Permit application requirements," please see the following applicable conditions as they relate to the Longview Power EGU.

4.3. The owner or operator of a unit shall provide a heat rate improvement analysis and the associated degree of emission limitation achievable for each unit as specified in subdivisions 4.3.a and 4.3.b.

The Longview Power Heat Rate Improvement analysis (summarized in Table 1 below) is based on the EPA guidance of best available technology (BAT) and the potential heat rate improvements (HRI) based on a unit greater than 500 MW. In Longview's case, all of the technical equipment solutions are part of the base design of the facility except for Neural Network/Intelligent Combustion and Intelligent Sootblowing, which were integrated after the Commercial Operating Date (COD). Intelligent Sootblowing created benefits due to reduction in reheat spray flow and improved heat transfer. Intelligent Combustion with the Neural Network allowed for a reduction in O_2 in boiler resulting in a heat rate benefit.

Table 1 has an assumption of an 8,800 btu/kwh baseline to calculate the targeted range of potential improvement proposed in EPA's Affordable Clean Energy (ACE) rule. 84 FED. REG. 32,520 (July 8, 2019). Additional columns are added to list the Longview results for both the post COD improvements (highlighted in yellow) and the technologies inherent in the base facility design (highlighted in green).

Table 1 - Longview Power Heat Rate Improvement

HRI Measure	> 500 MW		Longview Target (Btu/KWh)		Longview Captured (Btu/KWh)		Longview Potential (Btu/KWh)	
(Assuming 8,800 Btu/kwh baseline OPM heat rate)	% Min	% Max	Min	Max	Low	High	Low	High
*DCS / Neural Network / Intelligent Sootblowers	0.3	0.9	26.4	79.2	45.0	90.0	-	-
**Boiler Feed Pumps	0.2	0.5	17.6	44.0	17.6	44.0	-	-
**Air Heater & Duct Leakage Control	0.1	0.4	8.8	35.2	8.8	35.2	-	-
**Variable Frequency Drives	0.2	1.0	17.6	88.0	17.6	88.0	-	-
**Blade Path Ugrade (Steam Turbine)	1.0	2.9	88.0	255.2	88.0	255.2	-	-
**Redesign / Replace Economizer	0.5	1.0	44.0	88.0	44.0	88.0	-	-
**Improved Operating and Maintenance (O & M) Practices	-	2.0	-	176.0	-	176.0		
*Measured HRI Improvements	2.3	8.7	202.4	765.6	221.0	776.4	-	-
**Assumed Captured Due to Full Unit Baseline Incorporation					109%	101.4%	0.0%	0.0%

As discussed in further detail below, Longview has considered each of the best system of emission reduction (BSER) technologies and practices specifically enumerated in the ACE rule. Longview has already fully implemented six of the seven BSER technologies and practices. The only identified exception is the possibility of variable frequency drives (VFD) on some facility equipment; however, the technology used instead of VFD is equivalent to or better than VFD. In the very limited instances in which VFD could be added and provide some HRI, i.e. on condensate pumps, the expected costs of $750,000 to $1,200,000 for such a project compared with expected trivial HRI of 1 – 3 btu/kwh benefit in return demonstrates they would not be cost effective projects and would take longer than the life of the facility for a return on investment. Thus, Longview has been unable to identify any further HRI required by the ACE rule.

EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. EPA expects this to be a part of many state plans." 84 FED. REG. at 32,554. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO2 reductions." *Id.* at 32,553. Since Longview has already integrated the BSER technologies contemplated by the ACE rule (or in the case of VFDs an alternative providing even more HRI) into the design, construction and operation of the plant which have successfully achieved both high efficiency and low CO_2 emissions, and with any further trivial potential HRI not being cost effective, Longview is in compliance with the intent of the ACE rule without further HRI.

4.3.a. The permit application must include an applicability evaluation for each of the following heat rate improvements technologies identified in paragraphs 4.3.a.1 through 4.3.a.7 to each unit:

4.3.a.1. Neural Network and Intelligent Sootblowers:

Has this HRI been previously applied to the EGU?

Yes

What was the start-up date?

Neural Network DCS Upgrade / Replacement - June 2015
Intelligent Sootblowing - Fall 2015
Intelligent Combustion - Fall 2018

What HRI improvement was achieved?

The Distributed Control System (DCS) is a digital hardware/software process that takes a large number of operating data points across the plant's systems to control and adjust processes through a central control station. This initial upgrade enabled the inclusion of Intelligent Combustion and Intelligent Sootblowing in an efficient and cost effective manner.

Intelligent Combustion – Approximately 20 to 40 btu/kwh due to a 1% reduction in oxygen

Intelligent Sootblowing – Approximately 25 to 50 btu/kwh due to ability to control reheat spray and increase heat transfer in boiler

How much longer will the HRI be observed?

Sustained benefit for life of EGU with appropriate maintenance of systems

Are there further upgrades or improvements available with this technology?

No additional benefits identified. There is significant focus on daily activities to keep systems optimized for sustained benefit with fully staffed controls, reliability, and performance engineers and specialists.

4.3.a.2. Boiler Feed Pumps:

Has this HRI been previously applied to the EGU?

Yes, as part of base design. BFPs have a BAT Variable Speed Hydraulic Coupling to allow for efficient control and optimization of process.

What was the start-up date?

2011 original commissioning – Base Design of BFP is a leading design of efficiency.

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Pump performance will slowly degrade over time due to normal wear and tear. Longview has extensive condition and performance modeling programs, both in-house and via a third party, to insure pumps stay reliable and on pump curves to maintain efficiency over maintenance cycle of pumps. A pump rebuild is designed to take a pump back to near new performance so with proper maintenance the heat rate can be maintained.

Are there further upgrades or improvements available with this technology?

No. Current pump design and operation is consistent with BAT for new installations.

4.3.a.3. Air Heater and Duct Leakage Control:

Has this HRI been previously applied to the EGU?

Yes, as part of base design

What was the start-up date?

2011 original commissioning

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance. Air Heater distortion will occur over life of EGU which will degrade the sealing capability.

Are there further upgrades or improvements available with this technology?

No, technology applied is a BAT

4.3.a.4. Variable Frequency Drives:

Has this HRI been previously applied to the EGU?

Longview's design incorporates the use of variable pitch axial fans to control the input of air and exhaust of gases (balance draft unit). The intent of using VFDs is to provide increased efficiencies for older centrifugal fans commonly used on the bulk of the US's coal fleet. Longview due to its recent design makes use of the constant speed motive force but varies the pitch of the fan's blades to control flow. This results in greater efficiency for the motor in a manner that is equivalent to or better than the centrifugal fan/VFD format.[1] The use of variable pitch axial flow fans results in a 0.39% to 0.53% (full load benefit only) heat rate improvement over constant speed centrifugal fans while providing for better efficiency over a wider load range. Due to this, Longview does not expect that VFD would provide any additional HRI over the application of the axial flow fans currently installed.

What piece(s) of equipment (force-draft, induced-draft, pumps, etc.) have had VFDs installed?

Induced Draft Fans have Variable Blade Pitch Design
Forced Draft Fans have Variable Blade Pitch Design

What was the start-up date?

2011 original commissioning

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance

Are there further upgrades or improvements available with this technology?

Not with the air/fan systems - the axial variable blade pitch fan design is the current state of the art for power plant fan systems.

VFDs may provide some heat rate improvement in selected condensate pumps should the Longview unit face a significant change in its operating regime (i.e. increased low load cycling). However, the net efficiency gain from the use of VFDs on condensate pumps (0.014% to 0.028%) is considered marginal. The marginal benefit is due to the facility being base loaded with condensate pumps design and operation being at a very efficient point on the pump curve. The investment of $750,000 - $1,250,000 is not able to be recovered in current operating conditions. The comparison of

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[1] THE BABCOCK AND WILCOX COMPANY, STEAM/ITS GENERATION AND USE 25-19 (Gregory L. Tomei ed., 42nd ed. 2015) (noting that "[v]ariable pitch axial flow fans used in fossil power generating systems can be more efficient than equivalent centrifugal type fans" and "[s]everal major benefits observed from this figure for axial flow fans include … [t]he areas of constant efficiency run parallel to the boiler resistance line resulting in high efficiency over a wide boiler load range …").

marginal HRI with considerable cost do not make it a cost effective project (poor cost/benefit).

Is it technically feasible to apply this HRI at the unit (possibly on other equipment not previously utilizing a VFD)?

Yes

Please specify what piece of equipment (force-draft, induced-draft, pumps, etc.) would using a VFD technology improve the heat rate of the overall unit.

Condensate pumps – potential under very specific circumstances

Provide a detailed explanation why it is not technically feasible.

N/A

What percentage of HRI is achievable by applying this technology to this unit?

Based on operating data and review of the pump curve, it is projected that this application of VFD technology could provide an additional 0.014% to 0.028% heat rate improvement.

Is this percentage of HRI potential outside the range in Table 45CSR44?

Yes – Significant amount of equipment already has variable technologies. Additionally, based on Longview being a base-loaded facility and condensate pumps operating at an efficient load point at full load there is not significant incremental value in this case.

Provide an explanation why the HRI potential is different than the ranges in Table 45CSR44.

Significant amount of equipment already has BAT variable technologies. Additionally, based on Longview operating as a base-loaded facility, the condensate pumps operate at an efficient load point and as such there is not significant incremental value in this case. If the future facility capacity factor changed drastically and the unit was no longer operated as a base-load unit, this technology and application would be reassessed to determine value at that time.

4.3.a.5. Blade Path Upgrades for Steam Turbines:

Has this HRI been previously applied to the EGU?

Yes, as part of base design

What was the start-up date?

2011 original commissioning as part of base design, BAT applied

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance and may degrade between maintenance cycles recovering after turbine overhauls

Are there further upgrades or improvements available with this technology?

No, BAT already applied to EGU and no current steam path upgrade for our design

4.3.a.6. Redesign or Replacement of Economizer:

Has this HRI been previously applied to the EGU?

Yes, as part of base design

What was the start-up date?

2011 original commissioning as part of base design, BAT applied

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

With proper maintenance, performance can be sustained with very small amount of degradation

Are there further upgrades or improvements available with this technology?

No, current BAT applied in base design

4.3.a.7. Improved Operating and Maintenance Practices:

Has this HRI been previously applied to the EGU?

Yes

What was the start-up date?

Training began in 2013 and is ongoing.

What HRI improvement was achieved?

The facility uses a modern Computerized Managed Maintenance System (CMMS) (Maximo) to manage all maintenance activities. Additionally, a real-time ASME thermodynamic model is utilized to continuously monitor and assess unit performance including heat rate in an effort to prevent and/or mitigate performance degradation due to a variety of factors. This model is utilized by personnel both on site and remotely on a daily basis to track and adjust unit parameters to maintain optimal performance. Additionally, advanced monitoring and diagnostics with an artificial intelligence learning system is utilized continuously to identify changes in process that can impact reliability and performance of the facility. Longview utilizes 3rd party subject matter experts for performance to help troubleshoot or identify any abnormal operation or condition.

Having a well trained staff with knowledge on heat rate and efficiency principles is an enabler of sustained results. Training of all personnel was completed in 2013 with ongoing continuous employee knowledge development and continuous improvement. This training and fundamental knowledge is a baseline enabler of insuring the unit remains efficient and continuously improves. Unit performance is deeply embedded in the culture of the facility.

What was the cost to install?

Initial training with vendor in 2013 was approx. $30k in direct costs. The cost of our internal labor and lost time of labor in training is not part of cost. Ongoing training fits in the annual budget of employee development.

How much longer will the HRI be observed?

Sustained for life with appropriate ongoing communication and training

Are there further upgrades or improvements available with this technology?

Not at this time. Ongoing training will continue as warranted to ensure facility personnel have adequate knowledge to continue to effectively support the program.

4.4. The owner or operator shall propose and justify a standard of performance for each unit in the permit application that satisfies the following requirements:

The facility proposes the following:

4.4.a. Standard of Performance

The Longview Power PC EGU shall emit no more than 2,049 lbs/Mwh (net) CO_2 on a 3 year rolling annual average basis for an operating Net Output Factor (NOF) greater than 95%. Net Output Factor is a standard within NERC's Generation Availability Data System (GADS), a relationship of actual generation divided by maximum potential generation for time period when unit is operating. The standard of performance would require adjustment for any year with a lower NOF to account for lower efficiencies that occur at lower loads. Mwh (net) shall be calculated by measuring the auxiliary load at the auxiliary transformers Mwh (aux) and subtracting from the Gross MW reading Mwh (gross) with removal of non-production related auxiliary loads.

Compliance shall be determined by:

1. Calculating the CO_2 emissions on an hourly arithmetic average basis:

   CO_2 (lbs/hr) = 5.7e-7 * CO_2 (ppm) * Flow (Scfh) / 2000

   CO_2 lbs/Mwh (net) = CO_2 (lbs/hr) / Mwh (Net)

   Mwh (Net) = Mwh (gross) – Mwh (aux)

2. Calculating an annual average based on all operating hours

3. Calculating a rolling 3-year annual average CO_2 lb/Mwh (net) rate

   Data obtained during startup, shutdown, malfunction, or hourly periods of < 40% unit load shall be excluded from calculations.

The Standard of Performance target CO_2 lbs/Mwh (net) shall be increased at a rate of 2% every 5 years (+0.4% annually) to account for inevitable equipment efficiency losses over the life of the EGU.

4.4.b. Justification

After assessing the typical unit performance from 2012 to 2019, a baseline heat rate and in turn CO_2 rate was calculated based on validated CEMS data covering the time period from 2014 – 2019. Once this average was calculated, the standard deviation of the data set was then calculated, multiplied by three (3), and added to the six year average, creating a standard of performance representative to the actual unit of performance, and allowing for an appropriate level of variability. A summary of these calculations is provided in Table 2 below:

Table 2 - LVP Heat Rate and CO_2 Data

Period	OPM Heat Rate	CO_2
	Btu/Kwh, HHV	*lbs/Mwh*
2014	8,990	2,004
2015	8,938	1,943
2016	8,897	1,946
2017	8,783	1,947
2018	8,757	1,921
2019	8,684	1,899
Average	***8,842***	***1,943***
SD	***118***	***35***
Ave+3SD	**9,196**	**2,049**

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4.4.c. Compliance/Averaging Period

The compliance period shall be based on a three (3) year rolling annual average.

4.4.d. Compliance Schedule

The Longview Power PC EGU would demonstrate compliance beginning in the first full calendar year after permit issuance.

4.4.e. Monitoring

CO_2 (ppm) output concentrations shall be measured according to the provisions of 40 CFR Part 60.49Da(d).

Flow (scfh) shall be measured according to the provisions of 40 CFR Part 60.49Da(m).

Mwh (gross) shall be measured according to the provisions of 40 CFR Part 60.49Da(k).

4.4.f. Recordkeeping

Records shall be maintained for a minimum of 5 years via the CEMS/DAHS.

4.4.g. Reporting

CO_2 mass reporting (lbs/Mwh net) shall occur on an annual basis via a report submitted to EPA and WVDEP.

4.5 In applying a standard of performance to an affected steam generating unit, the owner or operator may take into consideration factors, such as the remaining useful life of such affected steam generating unit, provided the owner or operator demonstrates with respect to each such affected steam generating unit (or class of such affected steam generating units):

4.5.a. Unreasonable cost of control resulting from plant age, location, or basic process design;
4.5.b. Physical impossibility of installing necessary control equipment; or
4.5.c. Other unique factors that make application of a less stringent standard or final compliance time significantly more reasonable.

and

4.6 If the owner or operator considered remaining useful life and other factors for a designated facility, the application shall include a summary of how those factors were used in deriving a proposed standard of performance and must include a summary in the application of relevant factors from subsection 4.3 in deriving a proposed standard of performance.

As discussed in further detail herein, Longview has considered each of the BSER technologies and practices specifically enumerated in the ACE rule. Longview has already fully implemented six of the seven BSER technologies and practices. The only identified exception is the possibility of variable frequency drives (VFD) on some facility equipment; however, the technology used instead of VFD is equivalent to or better than VFD. In the very limited instances in which VFD could be added and provide some HRI, i.e. condensate pumps, the expected costs of such a project compared with expected trivial HRI demonstrate that they would not be cost effective projects. Thus, Longview has been unable to identify any further heat rate improvement (HRI) required by the ACE rule.

"Remaining useful life" was not considered in the analysis contained herein. EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. EPA expects this to be a part of many state plans." 84 FED. REG. at 32,554. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO2 reductions. Since Longview has already integrated the BSER technologies contemplated by the ACE rule (or in the case of VFDs an alternative providing even more HRI) into the design, construction and operation of the plant which have successfully achieved both high efficiency and low CO_2 emissions, and with any further trivial potential HRI not being cost effective, Longview is in compliance with the intent of the ACE rule without further HRI.

4.7 The owner or operator of an affected steam generating unit shall submit a compliance schedule with the permit application to the Secretary if the owner or operator requests a compliance date past July 8, 2024.

N/A

4.8 Standards of performance for affected steam generating units proposed in the application shall be demonstrated to be quantifiable, verifiable, permanent, and enforceable with respect to each affected steam generating unit. The application shall include the methods by which each standard of performance meets each of the following requirements:

Longview currently has a complete and effective Continuous Emissions Monitoring System (CEMS) that is monitored by applicable agencies. This system is subject to:

- Frequent calibration, effective maintenance and RATA testing
- Heat Rate degradation and improvements are currently monitored, evaluated and repaired/confirmed.
- Longview has demonstrated effective maintenance of all systems either routinely and/or through frequent outages.

The CEMS provides for effective monitoring in quantifiable and verifiable means and fully adopted industry practice. The identification and enforcement of non-compliant exceedances related to CO_2 would be reported and handled as current NOx and SO_2 issues. From a plant operations perspective, Longview would maintain compliance by continuing to use industry standard and regulatory compliant methods, as appropriate, and as the facility currently does for other air-related regulatory programs and standards.

A permit issued pursuant to this application will also make all standards of performance to be sufficiently "permanent" and "enforceable."

4.9 The application shall include the information listed below, as applicable:

4.9.a. A summary of each designated facility's anticipated future operation characteristics, including:

4.9.a.1. Annual generation;

4.9.a.2. CO_2 emissions;

4.9.a.3. Fuel use, fuel prices, fuel carbon content;

4.9.a.4. Fixed and variable operations and maintenance costs;

4.9.a.5. Heat rates; and

4.9.a.6. Electric generation capacity and capacity factors.

4.9.b. A timeline for implementation.

4.9.c. All wholesale electricity prices.

4.9.d. A time period of analysis, which must extend through at least 2035.

Longview is one of the lowest cost fossil fired generators in the PJM market place and thus is currently a base load unit. Many times, this facility dispatches ahead of most all gas fired combined cycle facilities. The ability to reliably deliver power under extreme cold weather with a secured fuel source provides the grid with the essential resilience and affordability.

The future of an open and competitive market place isn't subject to definitive future outcomes and, therefore, cannot be effectively forecasted to gain certainty to generation patterns, capacity factors, electric power prices, fuel use patterns or consumptions. Since these cannot be gained in a certain manner, maintenance efforts and associated costs cannot be accurately determined.

It is because of this reasoning that Longview can only forecast what a near-term expectation of net generation, capacity factors and maintenance requirements will be. Those detailed forecasts are critical and vital to Longview's competitiveness and are considered proprietary and confidential.

Given these limitations, and a projected unit service life of approximately 30 to 40 years, Longview believes that the future operations for this facility will remain as a base load unit with relatively high capacity factors and that maintenance efforts will remain sufficient to sustain reliability, compliance and safety of the facility well into the future. Any further attempted prediction of future operations is impossible; however, to do its best to comply with ACE rule and W. Va. C.S.R. § 45-44-4 requirements, Longview prepared Table 3 below which is a current estimate of expected future operation. Of note, the proposed substantive terms in this application are not contingent upon any prediction of future operation or factor. Thus, the information sought in W. Va. C.S.R. § 45-44-4.4.9 (and its inherent uncertainty) are not expected to be "applicable" as they do not affect this application and a permit issued pursuant to it.

Table 3 - LVP Anticipated Future Operation Characteristics

45CSR44 Reference	Parameter	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4.9.a.1.	Annual Net Generation (GWh)	5,087	5,250	5,410	5,174	5,124	5,368	5,423	5,514	5,470	5,191	5,571	5,454	5,416	5,290	4,991	5,548
4.9.a.2.	CO2 Emissions (000 tons)	5,212	5,400	5,587	5.365	5,286	5,560	5,640	5,757	5,734	5,415	5.834	5,734	5,717	5,606	5,311	5,874
4.9.a.3.	Fuel Use (000 tons)	1,758	1,822	1,885	1,810	1,783	1,876	1,903	1,942	1,934	1,827	1,968	1,935	1,929	1,891	1,792	1,982
4.9.a.3.	Fuel Carbon Content (000 tons)	1,231	1,275	1,319	1.267	1,248	1,313	1,332	1.360	1,354	1,279	1,378	1.354	1,350	1,324	1,254	1,387
4.9.a.5.	Heat Rates (btu/kWh)	8,815	8,851	8,886	8,922	8,877	8,912	8,948	8,984	9,020	8,975	9,011	9,047	9,083	9,119	9,156	9,110
4.9.a.6.	Electric Generation Capacity	6,149	6,132	6,132	6,132	6,149	6,132	6,132	6,132	6,149	6.132	6.132	6,132	6,149	6.132	6,132	6,132
4.9.a.6.	Capacity Factor	83%	86%	88%	84%	83%	88%	88%	90%	89%	85%	91%	89%	88%	86%	81%	90%

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Attachment A: Business Certificate

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Attachment A: Business Certificate

WEST VIRGINIA
STATE TAX DEPARTMENT
BUSINESS REGISTRATION CERTIFICATE

ISSUED TO:
LONGVIEW POWER LLC
85 WELLS AVE STE 300
NEWTON, MA 02459-3215

BUSINESS REGISTRATION ACCOUNT NUMBER: **1006-4407**

This certificate is issued on: 06/28/2010

This certificate is issued by the West Virginia State Tax Commissioner in accordance with W.Va. Code § 11-12.

The person or organization identified on this certificate is registered to conduct business in the State of West Virginia at the location above.

This certificate is not transferrable and must be displayed at the location for which issued.

This certificate shall be permanent until cessation of the business for which the certificate of registration was granted or until it is suspended, revoked or cancelled by the Tax Commissioner.

Change in name or change of location shall be considered a cessation of the business and a new certificate shall be required.

TRAVELING/STREET VENDORS: Must carry a copy of this certificate in every vehicle operated by them. CONTRACTORS, DRILLING OPERATORS, TIMBER/LOGGING OPERATIONS: Must have a copy of this certificate displayed at every job site within West Virginia.

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Attachment B: Map to Facility

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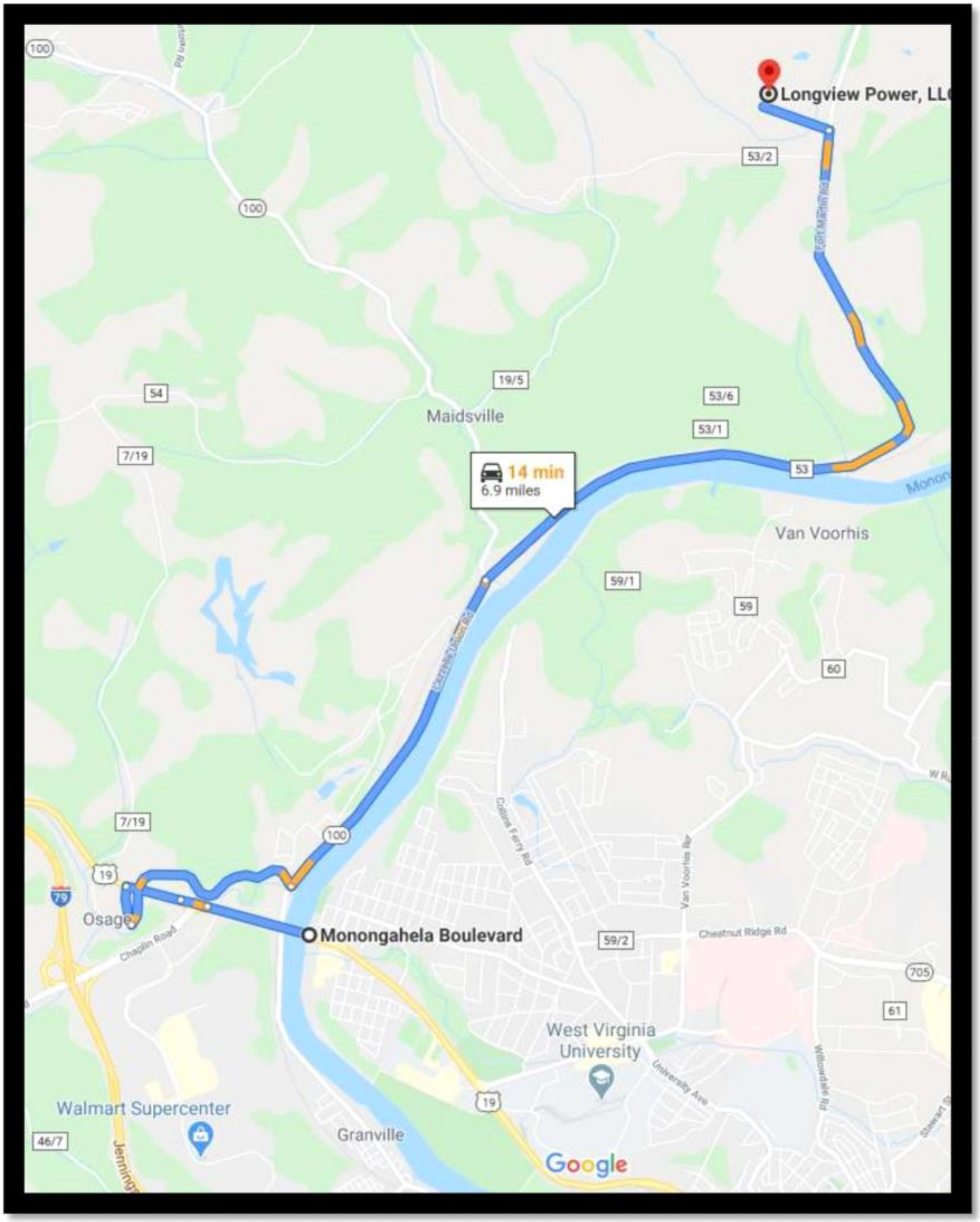
Attachment B: Map to Facility



Site Location Map

USGS 7.5 Minute Series Topographic Map

Morgantown North, W.Va. Quadrangle

Longview Power, LLC

Attachment C: Compliance Schedule

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Attachment C: Compliance Schedule

Longview Power intends to demonstrate compliance with the permit and associated Standard of Performance for the reporting year following issuance of the permit. Based on the current timeline and regulatory process, compliance would be demonstrated for reporting year 2021 no later than the end of March 31st, 2022.

Attachment D: Regulatory Discussion

Wednesday, October 7, 2020   3:31 PM

Attachment D: Regulatory Discussion

Longview Power is applying for a voluntary permit under 45CSR13 to address future requirements related to implementation of Best System of Emissions Reduction (BSER) under 40 CFR 60, Subpart UUUUa (Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units - ACE Rule). At this time, Longview has considered each of the BSER technologies and practices specifically enumerated in the ACE Rule, along with the associated Heat Rate Improvements (HRI). Based on this assessment and information included within this application, and since Longview demonstrates compliance with the intent of the ACE rule without further BSER implementation or HRI, it is therefore applying for this voluntary permit.

Attachment E Plot Plan

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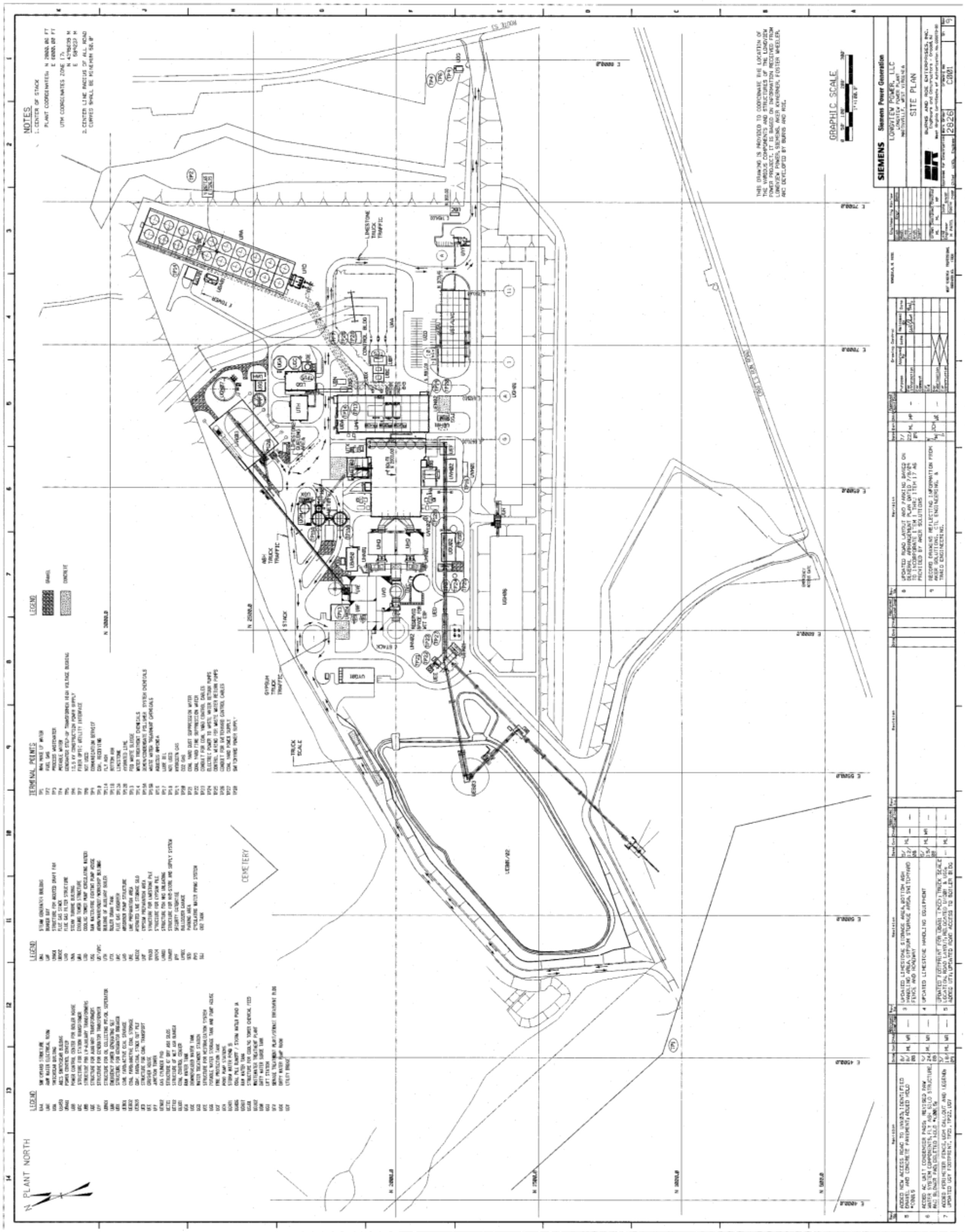
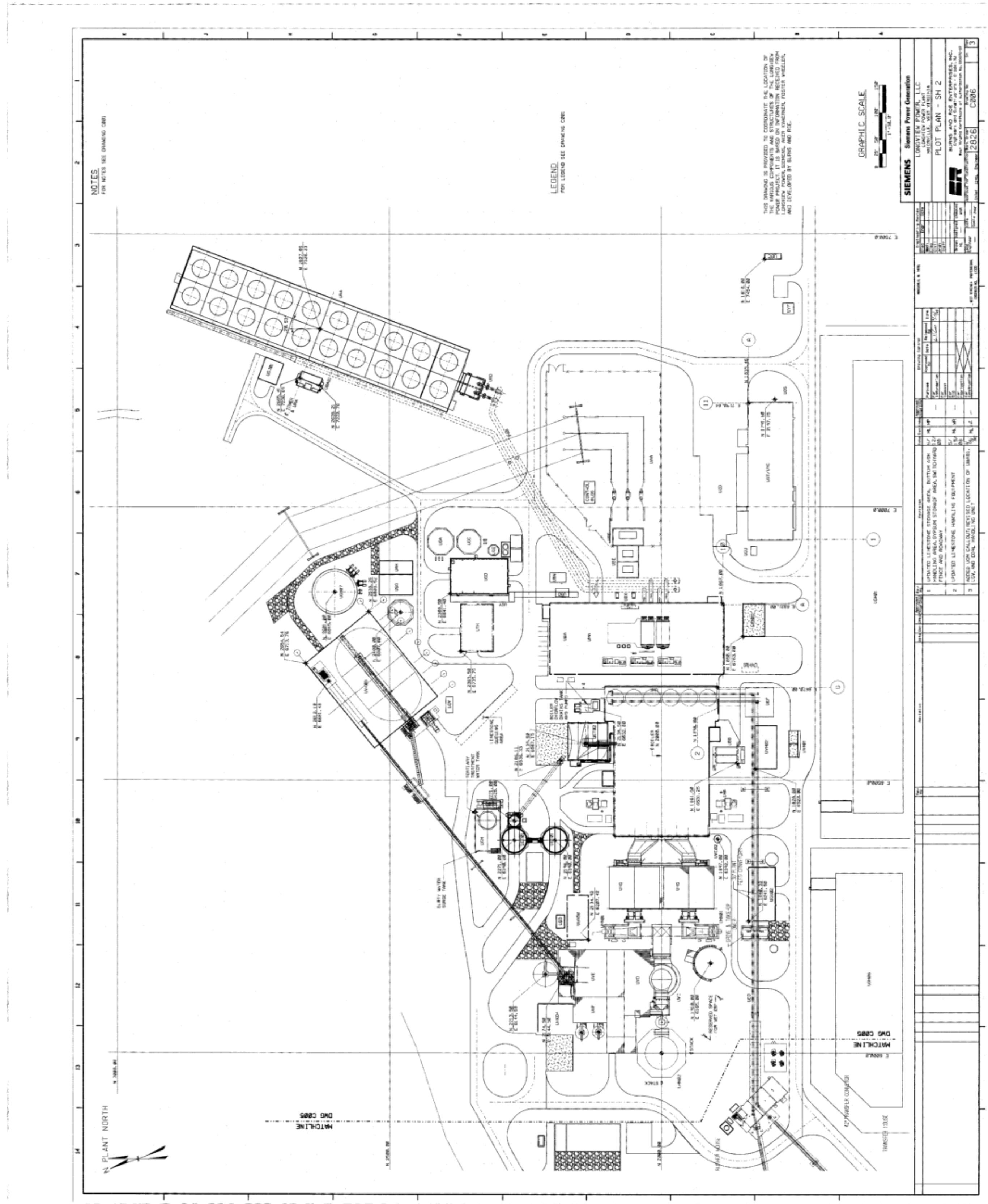
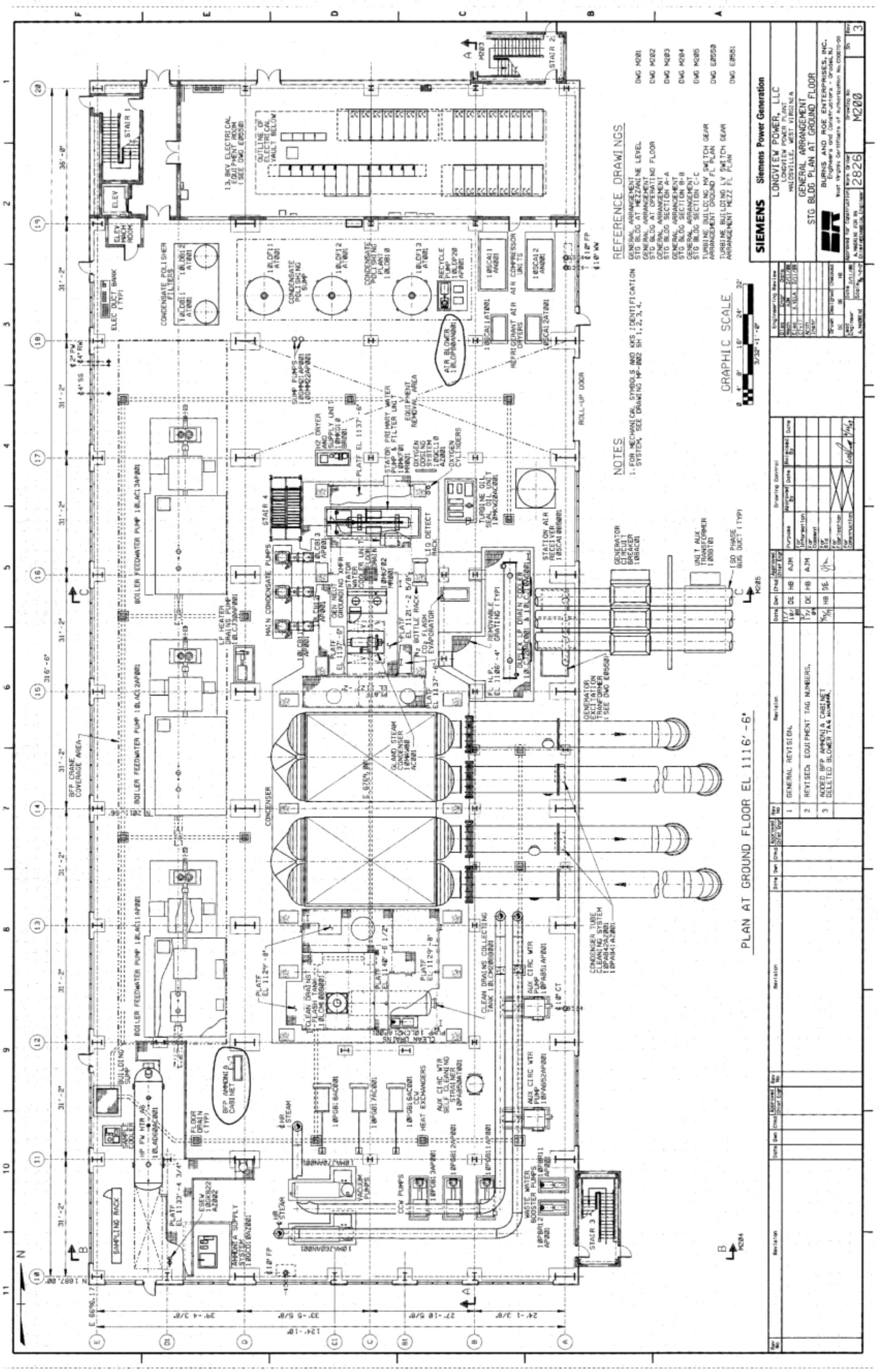
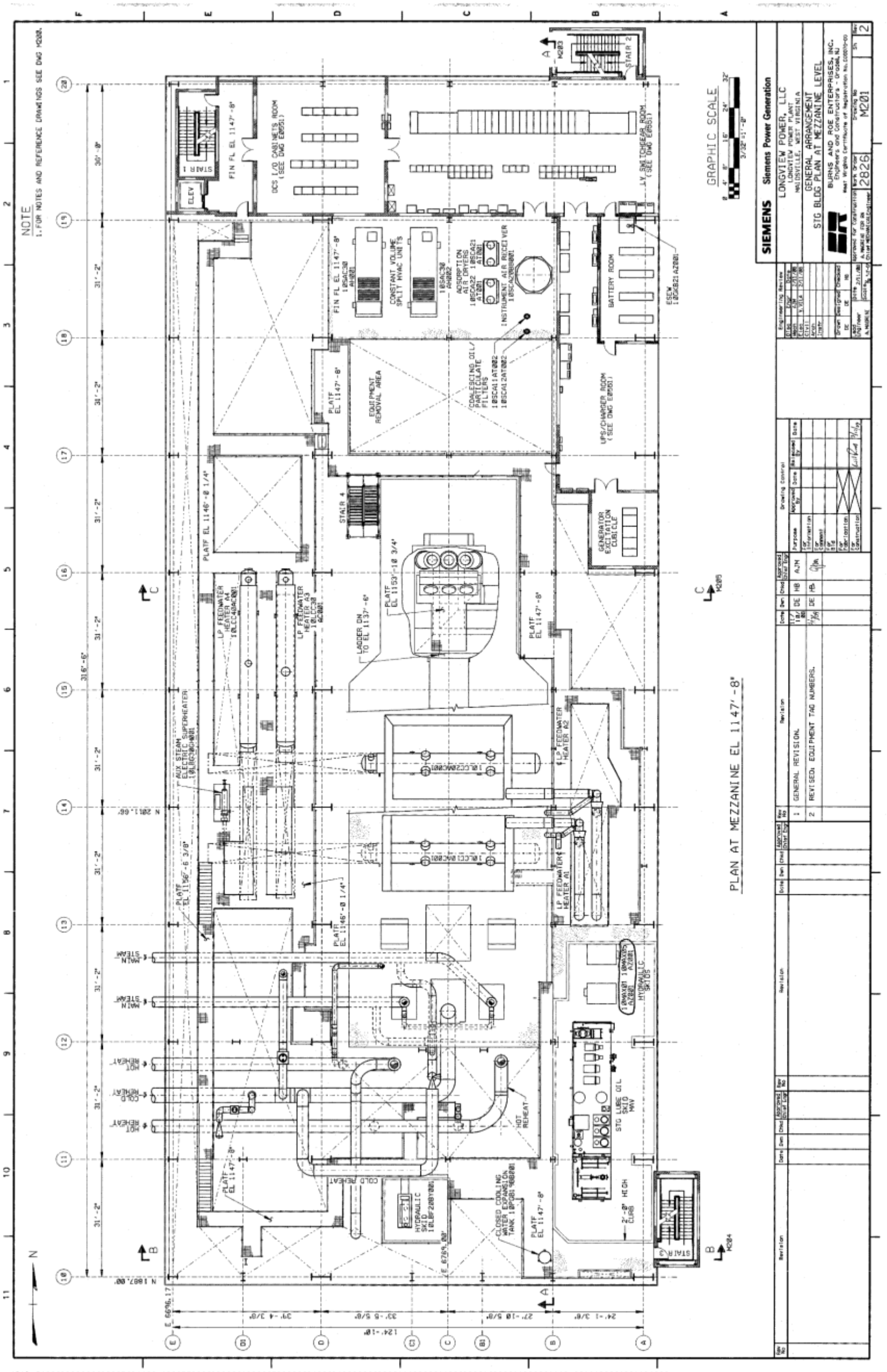
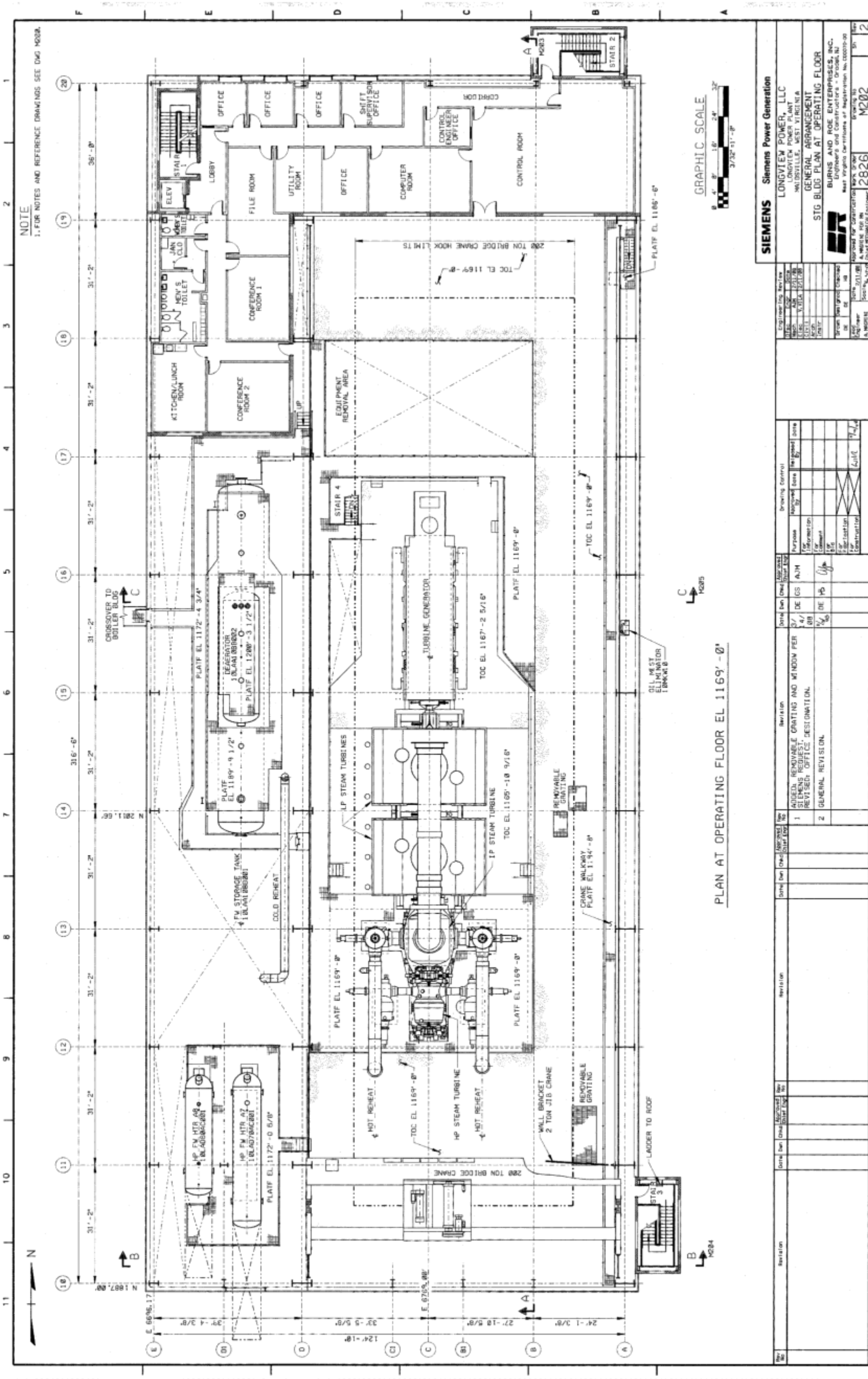

NOTES
LEGEND
TERMINAL POINTS
CEMETERY
PLANT NORTH
GRAPHIC SCALE
SIEMENS
Siemens Power Generation
LONGVIEW POWER, LLC
SITE PLAN


NOTES
LEGEND
GRAPHIC SCALE
SIEMENS
PLOT PLAN - SH 2
MATCHLINE
DWG C005
PLANT NORTH


PLAN AT GROUND FLOOR EL 1116'-6"
SIEMENS
Siemens Power Generation
LONGVIEW POWER, LLC
GENERAL ARRANGEMENT
STG BLDG PLAN AT GROUND FLOOR
REFERENCE DRAWINGS
NOTES
GRAPHIC SCALE


PLAN AT MEZZANINE EL 1147'-8"
GRAPHIC SCALE
SIEMENS
Siemens Power Generation
LONGVIEW POWER, LLC


PLAN AT OPERATING FLOOR EL 1169'-0"
GRAPHIC SCALE
SIEMENS Siemens Power Generation
LONGVIEW POWER, LLC
GENERAL ARRANGEMENT
STG BLDG PLAN AT OPERATING FLOOR
BURNS AND ROE ENTERPRISES, INC.
M202

Attachment F: Process Flow Diagram

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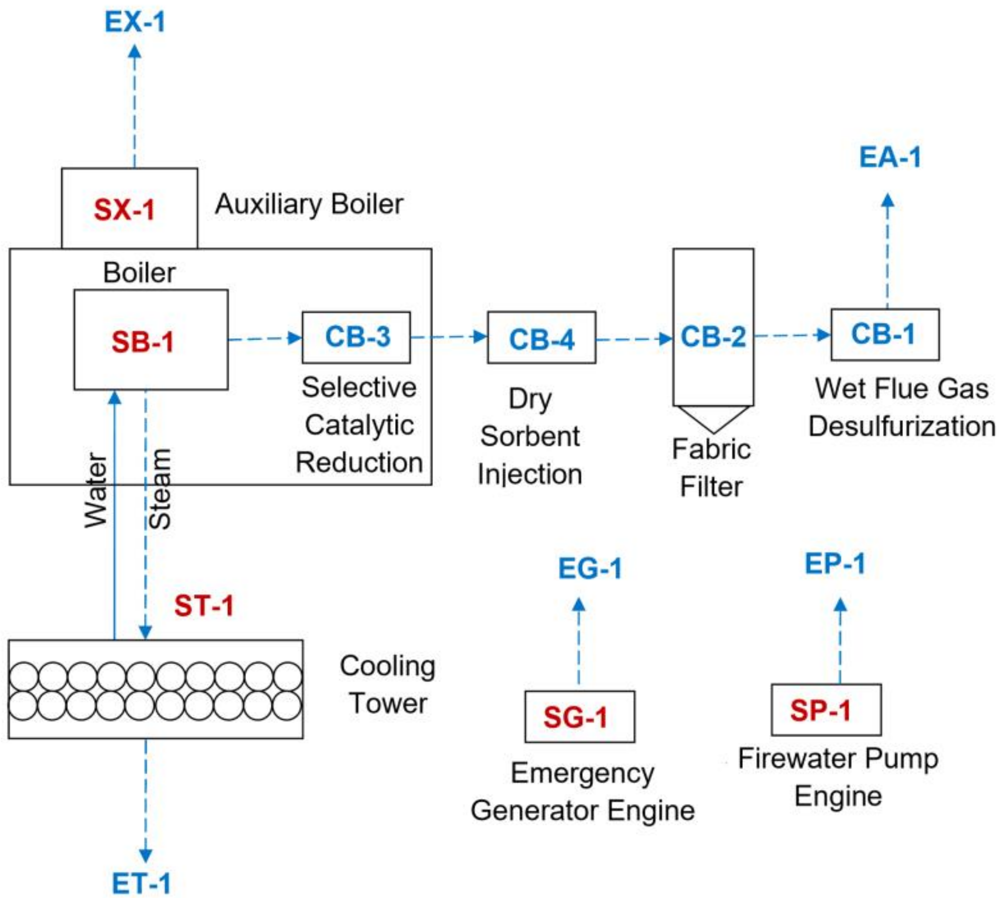
Attachment F: Process Flow Diagram



Attachment G: Process Description

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Attachment G: Process Description

Emissions Unit SB-1 – PC Boiler

Longview Power is an electric generating unit with a 6,114 MMBtu/hr supercritical pulverized coal fired steam generator and a natural gas fired auxiliary boiler, with associated equipment including coal, limestone, and ash handling, cooling tower, an emergency generator, and a fire pump

Primary SIC 4911; Secondary CIC NA; Tertiary SIC NA

SB-1 – PC Boiler is specifically a Foster Wheeler-BENSON Vertical once-through, supercritical steam generating unit consists of a vertical tube water wall furnace, primary superheater, platen superheater, finishing superheater, single stage reheater, and economizer.

Attachment N: Supporting Emissions Calculations

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Attachment N: Supporting Emissions Calculations

Per W. Va. C.S.R. § 45-44-4, "Permit application requirements," please see the following applicable conditions as they relate to the Longview Power EGU.

4.3. The owner or operator of a unit shall provide a heat rate improvement analysis and the associated degree of emission limitation achievable for each unit as specified in subdivisions 4.3.a and 4.3.b.

The Longview Power Heat Rate Improvement analysis (summarized in Table 1 below) is based on the EPA guidance of best available technology (BAT) and the potential heat rate improvements (HRI) based on a unit greater than 500 MW. In Longview's case, all of the technical equipment solutions are part of the base design of the facility except for Neural Network/Intelligent Combustion and Intelligent Sootblowing, which were integrated after the Commercial Operating Date (COD). Intelligent Sootblowing created benefits due to reduction in reheat spray flow and improved heat transfer. Intelligent Combustion with the Neural Network allowed for a reduction in O_2 in boiler resulting in a heat rate benefit.

Table 1 has an assumption of an 8,800 btu/kwh baseline to calculate the targeted range of potential improvement proposed in EPA's Affordable Clean Energy (ACE) rule. 84 FED. REG. 32,520 (July 8, 2019). Additional columns are added to list the Longview results for both the post COD improvements (highlighted in yellow) and the technologies inherent in the base facility design (highlighted in green).

Table 1 - Longview Power Heat Rate Improvement

HRI Measure	> 500 MW		Longview Target (Btu/KWh)		Longview Captured (Btu/KWh)		Longview Potential (Btu/KWh)	
(Assuming 8,800 Btu/kwh baseline OPM heat rate)	% Min	% Max	Min	Max	Low	High	Low	High
*DCS / Neural Network / Intelligent Sootblowers	0.3	0.9	26.4	79.2	45.0	90.0	-	-
**Boiler Feed Pumps	0.2	0.5	17.6	44.0	17.6	44.0	-	-
**Air Heater & Duct Leakage Control	0.1	0.4	8.8	35.2	8.8	35.2	-	-
**Variable Frequency Drives	0.2	1.0	17.6	88.0	17.6	88.0	-	-
**Blade Path Ugrade (Steam Turbine)	1.0	2.9	88.0	255.2	88.0	255.2	-	-
**Redesign / Replace Economizer	0.5	1.0	44.0	88.0	44.0	88.0	-	-
**Improved Operating and Maintenance (O & M) Practices	-	2.0	-	176.0	-	176.0		
*Measured HRI Improvements	**2.3**	**8.7**	**202.4**	**765.6**	**221.0**	**776.4**	-	-
**Assumed Captured Due to Full Unit Baseline Incorporation					109%	101.4%	0.0%	0.0%

As discussed in further detail below, Longview has considered each of the best system of emission reduction (BSER) technologies and practices specifically enumerated in the ACE rule. Longview has already fully implemented six of the seven BSER technologies and practices. The only identified exception is the possibility of variable frequency drives (VFD) on some facility equipment; however, the technology used instead of VFD is believed to be equivalent to or better than VFD. In the very limited instances in which VFD could be added and provide some HRI, i.e. on condensate pumps, the expected costs of such a project compared with expected trivial HRI in return demonstrate they they would not be cost effective projects. Thus, Longview has been unable to identify any further HRI required by the ACE rule.

EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. EPA expects this to be a part of many state plans." 84 FED. REG. at 32,554. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO2 reductions." *Id.* at 32,553. Since Longview has most of the BSER technologies already fully integrated into the design, construction and operation of the plant which have successfully achieved both high efficiency and low CO_2 emissions, and with any further HRI not being cost effective, Longview is in compliance with the intent of the ACE rule without further HRI.

4.3.a. The permit application must include an applicability evaluation for each of the following heat rate improvements technologies identified in paragraphs 4.3.a.1 through 4.3.a.7 to each unit:

4.3.a.1. Neural Network and Intelligent Sootblowers:

Has this HRI been previously applied to the EGU?

Yes

What was the start-up date?

Neural Network DCS Upgrade / Replacement - June 2015
Intelligent Sootblowing - Fall 2015
Intelligent Combustion - Fall 2018

What HRI improvement was achieved?

The Distributed Control System (DCS) is a digital hardware/software process that takes a large number of operating data points across the plant's systems to control and adjust processes through a central control station. This initial upgrade enabled the inclusion of Intelligent Combustion and Intelligent Sootblowing in an efficient and cost effective manner.

Intelligent Combustion – Approximately 20 to 40 btu/kwh due to a 1% reduction in oxygen

Intelligent Sootblowing – Approximately 25 to 50 btu/kwh due to ability to control reheat spray and increase heat transfer in boiler

How much longer will the HRI be observed?

Sustained benefit for life of EGU with appropriate maintenance of systems

Are there further upgrades or improvements available with this technology?

No additional benefits identified. There is significant focus on daily activities to keep systems optimized for sustained benefit with fully staffed controls, reliability, and performance engineers and specialists.

4.3.a.2. Boiler Feed Pumps:

Has this HRI been previously applied to the EGU?

Yes, as part of base design. BFPs have a BAT Variable Speed Hydraulic Coupling to allow for efficient control and optimization of process.

Longview's unique boiler feedpump design utilizes a constant speed motor directly coupled to a condensate booster pump that provides sufficient suction head for the feedwater pump, which is in turn coupled to the same motor through a VOITH variable speed hydraulic coupling that permits precise and stepless speed control. This speed control allows the feedpump to vary flow in the same fashion as a Variable Frequency Drive (VFD) pump without the throttling losses of a constant speed pump configuration. A retrofit to a VFD would require an additional motor to drive the condensate booster pump and would not gain any efficiency due to reduced throttling losses.

What was the start-up date?

2011 original commissioning – Base Design of BFP is a leading design of efficiency.

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Pump performance will slowly degrade over time due to normal wear and tear. Longview has extensive condition and performance modeling programs, both in-house and via a third party, to insure pumps stay reliable and on pump curves to maintain efficiency over maintenance cycle of pumps. A pump rebuild is designed to take a pump back to near new performance so with proper maintenance the heat rate can be maintained.

Are there further upgrades or improvements available with this technology?

No. Current pump design and operation is consistent with BAT for new installations.

4.3.a.3. Air Heater and Duct Leakage Control:

Has this HRI been previously applied to the EGU?

Yes, as part of base design.

What was the start-up date?

2011 original commissioning

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance. Air Heater distortion will occur over life of EGU which will degrade the sealing capability.

Are there further upgrades or improvements available with this technology?

No, technology applied is a BAT

4.3.a.4. Variable Frequency Drives;

Has this HRI been previously applied to the EGU?

Longview's design incorporates the use of variable pitch axial fans to control the input of air and exhaust of gases (balance draft unit). The intent of using VFDs is to provide increased efficiencies for older centrifugal fans commonly used on the bulk of the US's coal fleet. Longview due to its recent design makes use of the constant speed motive force but varies the pitch of the fan's blades to control flow. This results in greater efficiency for the motor in a manner that is equivalent to or better than the centrifugal fan/VFD format. Due to this, Longview does not expect that VFD would provide any additional HRI.

What piece(s) of equipment (force-draft, induced-draft, pumps, etc.) have had VFDs installed?

Induced Draft Fans have Variable Blade Pitch Design
Forced Draft Fans have Variable Blade Pitch Design

What was the start-up date?

2011 original commissioning

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance

Are there further upgrades or improvements available with this technology?

Not with the air/fan systems - the axial variable blade pitch fan design is the current state of the art for power plant fan systems.

VFDs may provide some heat rate improvement in selected condensate pumps should the Longview unit face a significant change in its operating regime (i.e. increased low load cycling). However, the net efficiency gain from the use of VFDs on condensate pumps (0.014% to 0.028%) is considered marginal. The comparison of marginal HRI with considerable cost do not make it a cost effective project (poor cost/benefit).

Is it technically feasible to apply this HRI at the unit (possibly on other equipment not previously utilizing a VFD)?

Yes

Please specify what piece of equipment (force-draft, induced-draft, pumps, etc.) would using a VFD technology improve the heat rate of the overall unit.

Condensate pumps – potential under very specific circumstances

Provide a detailed explanation why it is not technically feasible.

N/A

What percentage of HRI is achievable by applying this technology to this unit?

Based on operating data and review of the pump curve, it is projected that this application of VFD technology could provide an additional 0.014% to 0.028% heat rate improvement.

Is this percentage of HRI potential outside the range in Table 45CSR44?

Yes – Significant amount of equipment already has variable technologies. Additionally, based on Longview being a base-loaded facility and condensate pumps operating at an efficient load point at full load there is not significant incremental value in this case.

Provide an explanation why the HRI potential is different than the ranges in Table 45CSR44.

Significant amount of equipment already has BAT variable technologies. Additionally, based on Longview operating as a base-loaded facility, the condensate pumps operate at an efficient load point and as such there is not significant incremental value in this case. If the future facility capacity factor changed drastically and the unit was no longer operated as a base-load unit, this technology and application would be reassessed to determine value at that time.

4.3.a.5. Blade Path Upgrades for Steam Turbines:

Has this HRI been previously applied to the EGU?

Yes, as part of base design.

Per consultation with Siemens, the OEM of Longview's Steam Turbine, there are no uprates or efficiency improvement for the HP, IP, or LP turbines. Longview's turbines are state-of-the-art and the most modern available.

What was the start-up date?

2011 original commissioning as part of base design, BAT applied.

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance and may degrade between maintenance cycles recovering after turbine overhauls

Are there further upgrades or improvements available with this technology?

No, BAT already applied to EGU and no current steam path upgrade for our design

4.3.a.6. Redesign or Replacement of Economizer:

Has this HRI been previously applied to the EGU?

Yes, as part of base design.

Longview's original Economizer design has significant surface area and it very efficient in relation to economizers typically installed in legacy coal units. This is evident at full load in the relatively low boiler outlet gas temperatures: 650F to 670F range. This lower outlet gas temperature is an original design feature and that same original design had to utilize an economizer bypass duct to maintain SCR inlet temperatures greater than 670F for required NOx removal requirements. Additional heat transfer in this area would be counteracted by having to bypass additional flue gas to maintain temperatures for NOx removal creating no benefit.

What was the start-up date?

2011 original commissioning as part of base design, BAT applied

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

With proper maintenance, performance can be sustained with very small amount of degradation

Are there further upgrades or improvements available with this technology?

No, current BAT applied in base design

4.3.a.7. Improved Operating and Maintenance Practices:

Has this HRI been previously applied to the EGU?

Yes

What was the start-up date?

Training began in 2013 and is ongoing.

What HRI improvement was achieved?

The facility uses a modern Computerized Managed Maintenance System (CMMS) (Maximo) to manage all maintenance activities. Additionally, a real-time ASME thermodynamic model is utilized to continuously monitor and assess unit performance including heat rate in an effort to prevent and/or mitigate performance degradation due to a variety of factors. This model is utilized by personnel both on site and remotely on a daily basis to track and adjust unit parameters to maintain optimal performance. Additionally, advanced monitoring and diagnostics with an artificial intelligence learning system is utilized continuously to identify changes in process that can impact reliability and performance of the facility. Longview utilizes 3rd party subject matter experts for performance to help troubleshoot or identify any abnormal operation or condition.

Having a well trained staff with knowledge on heat rate and efficiency principles is an enabler of sustained results. Training of all personnel was completed in 2013 with ongoing continuous employee knowledge development and continuous improvement. This training and fundamental knowledge is a baseline enabler of insuring the unit remains efficient and continuously improves. Unit performance is deeply embedded in the culture of the facility.

What was the cost to install?

Initial training with vendor in 2013 was approx. $30k in direct costs. The cost of our internal labor and lost time of labor in training is not part of cost. Ongoing training fits in the annual budget of employee development.

How much longer will the HRI be observed?

Sustained for life with appropriate ongoing communication and training

Are there further upgrades or improvements available with this technology?

Not at this time. Ongoing training will continue as warranted to ensure facility personnel have adequate knowledge to continue to effectively support the program.

4.4. The owner or operator shall propose and justify a standard of performance for each unit in the permit application that satisfies the following requirements:

The facility proposes the following:

Standard of Performance

The Longview Power PC EGU shall emit no more than 2,049 lbs/Mwh (net) CO_2 on a 3 year rolling annual average basis for an operating Net Output Factor (NOF) greater than 95%. Net Output Factor is a standard within NERC's Generation Availability Data System (GADS), a relationship of actual generation divided by maximum potential generation for time period when unit is operating. The standard of performance would require adjustment for any year with a lower NOF to account for lower efficiencies that occur at lower loads. Mwh (net) shall be calculated by measuring the auxiliary load at the auxiliary transformers Mwh (aux) and subtracting from the Gross MW reading Mwh (gross) with removal of non-production related auxiliary loads.

Compliance shall be determined by:

1. Calculating the CO_2 emissions on an hourly arithmetic average basis:

CO_2 (lbs/hr) = 5.7e-7 * CO_2 (ppm) * Flow (Scfh) / 2000

CO_2 lbs/Mwh (net) = CO_2 (lbs/hr) / Mwh (Net)

Mwh (Net) = Mwh (gross) – Mwh (aux)

2. Calculating an annual average based on all operating hours

3. Calculating a rolling 3-year annual average CO_2 lb/Mwh (net) rate

Data obtained during startup, shutdown, malfunction, or hourly periods of < 40% unit load shall be excluded from calculations.

The Standard of Performance target CO2 lbs/Mwh (net) shall be increased at a rate of 2% every 5 years (+0.4% annually) to account for inevitable equipment efficiency losses over the life of the EGU. All power plants performance will degrade over time due to normal wear and degradation of systems that lose performance. Longview is recommending a 2% increase in standard over a 5 year period averaging at 0.4% per year increase. Longview is saying that over a longer period some of this loss will be recovered in maintenance cycles to include improvements after major maintenance cycles with examples such as major pump rebuilds, major fan rebuilds, major turbine overhauls, cooling tower maintenance. Longview recommends that over a 10 year period that the total increase would not exceed 3%.

For reference, https://energycentral.com/c/pip/heat-rate-reduction-thermal-power-generation-plants-leveraging-big-data-analytics

Justification

After assessing the typical unit performance from 2012 to 2019, a baseline heat rate and in turn CO_2 rate was calculated based on validated CEMS data covering the time period from 2014 – 2019. Once this average was calculated, the standard deviation of the data set was then calculated, multiplied by three (3), and added to the six year average, creating a standard of performance representative to the actual unit of performance, and allowing for an appropriate level of variability.

Table 2 - LVP Heat Rate and CO_2 Data		
Period	**OPM Heat Rate**	**CO_2**
	Btu/Kwh, HHV	*lbs/Mwh*
2014	8,990	2,004
2015	8,938	1,943
2016	8,897	1,946
2017	8,783	1,947
2018	8,757	1,921
2019	8,684	1,899
Average	***8,842***	***1,943***
SD	***118***	***35***
Ave+3SD	**9,196**	**2,049**

Compliance Schedule

The Longview Power PC EGU would demonstrate compliance beginning in the first full calendar year after permit issuance.

Monitoring

CO_2 (ppm) output concentrations shall be measured according to the provisions of 40 CFR Part 60.49Da(d).

Flow (scfh) shall be measured according to the provisions of 40 CFR Part 60.49Da(m).

Mwh (gross) shall be measured according to the provisions of 40 CFR Part 60.49Da(k).

Recordkeeping

Records shall be maintained for a minimum of 5 years via the CEMS/DAHS.

Reporting

CO_2 mass reporting (lbs/Mwh net) shall occur on an annual basis via a report submitted to EPA and WVDEP.

Compliance/Averaging Period

The compliance period shall be based on a three (3) year rolling annual average.

4.5 N/A

4.6 If the owner or operator considered remaining useful life and other factors for a designated facility, the application shall include a summary of how those factors were used in deriving a proposed standard of performance and must include a summary in the application of relevant factors from subsection 4.3 in deriving a proposed standard of performance.

As discussed in further detail herein, Longview has considered each of the BSER technologies and practices specifically enumerated in the ACE rule. Longview has already fully implemented six of the seven BSER technologies and practices. The only identified exception is the possibility of variable frequency drives (VFD) on some facility equipment; however, the technology used instead of VFD is believed to be equivalent to or better than VFD. In the very limited instances in which VFD could be added and provide some HRI, i.e. condensate pumps, the expected costs of such a project compared with expected trivial HRI demonstrate that they would not be cost effective projects. Thus, Longview has been unable to identify any further heat rate improvement (HRI) required by the ACE rule.

"Remaining useful life" was not considered in the analysis contained herein. EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. EPA expects this to be a part of many state plans." 84 FED. REG. at 32,554. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO2 reductions. Since Longview has most of the BSER technologies already fully integrated into the design, construction and operation of the plant which have successfully achieved both high efficiency and low CO_2 emissions, and with any further HRI not being cost effective, Longview is in compliance with the intent of the ACE rule without further HRI.

4.7 The owner or operator of an affected steam generating unit shall submit a compliance schedule with the permit application to the Secretary if the owner or operator requests a compliance date past July 8, 2024.

N/A

4.8 Standards of performance for affected steam generating units proposed in the application shall be demonstrated to be quantifiable, verifiable, permanent, and enforceable with respect to each affected steam generating unit. The application shall include the methods by which each standard of performance meets each of the following requirements:

Longview currently has a complete and effective Continuous Emissions Monitoring System (CEMS) that is monitored by applicable agencies. This system is subject to:

- Frequent calibration, effective maintenance and RATA testing
- Heat Rate degradation and improvements are currently monitored, evaluated and repaired/confirmed.
- Longview has demonstrated effective maintenance of all systems either routinely and/or through frequent outages.

The CEMS provides for effective monitoring in quantifiable and verifiable means and fully adopted industry practice. The identification and enforcement of non-compliant exceedances related to CO_2 would be reported and handled as current NOx and SO_2 issues. From a plant operations perspective, Longview would maintain compliance by continuing to use industry standard and regulatory compliant methods, as appropriate, and as the facility currently does for other air-related regulatory programs and standards.

A permit issued pursuant to this application will also make all standards of performance to be sufficiently "permanent" and "enforceable."

4.9 The application shall include the information listed below, as applicable: N/A

Longview is one of the lowest cost fossil fired generators in the PJM market place and thus is currently a base load unit. Many times, this facility dispatches ahead of most all gas fired combined cycle facilities. The ability to reliably deliver power under extreme cold weather with a secured fuel source provides the grid with the essential resilience and affordability.

The future of an open and competitive market place isn't subject to definitive future outcomes and, therefore, cannot be effectively forecasted to gain certainty to generation patterns, capacity factors, electric power prices, fuel use patterns or consumptions. Since these cannot be gained in a certain manner, maintenance efforts and associated costs cannot be accurately determined.

It is because of this reasoning that Longview can only forecast what a near-term expectation of net generation, capacity factors and maintenance requirements will be. Those detailed forecasts are critical and vital to Longview's competitiveness and are considered proprietary and confidential.

Given these limitations, and a projected unit service life of approximately 30 to 40 years Longview believes that the future operations for this facility will remain as a base load unit with relatively high capacity factors and that maintenance efforts will remain sufficient to sustain reliability, compliance and safety of the facility well into the future. Any further attempted prediction of future operations is impossible; however, this impossibility did not affect Longview's analysis required of it under the ACE rule as contained in this application.

Heat Rate Degradation Support - LVP

Tuesday, August 18, 2020 8:21 AM

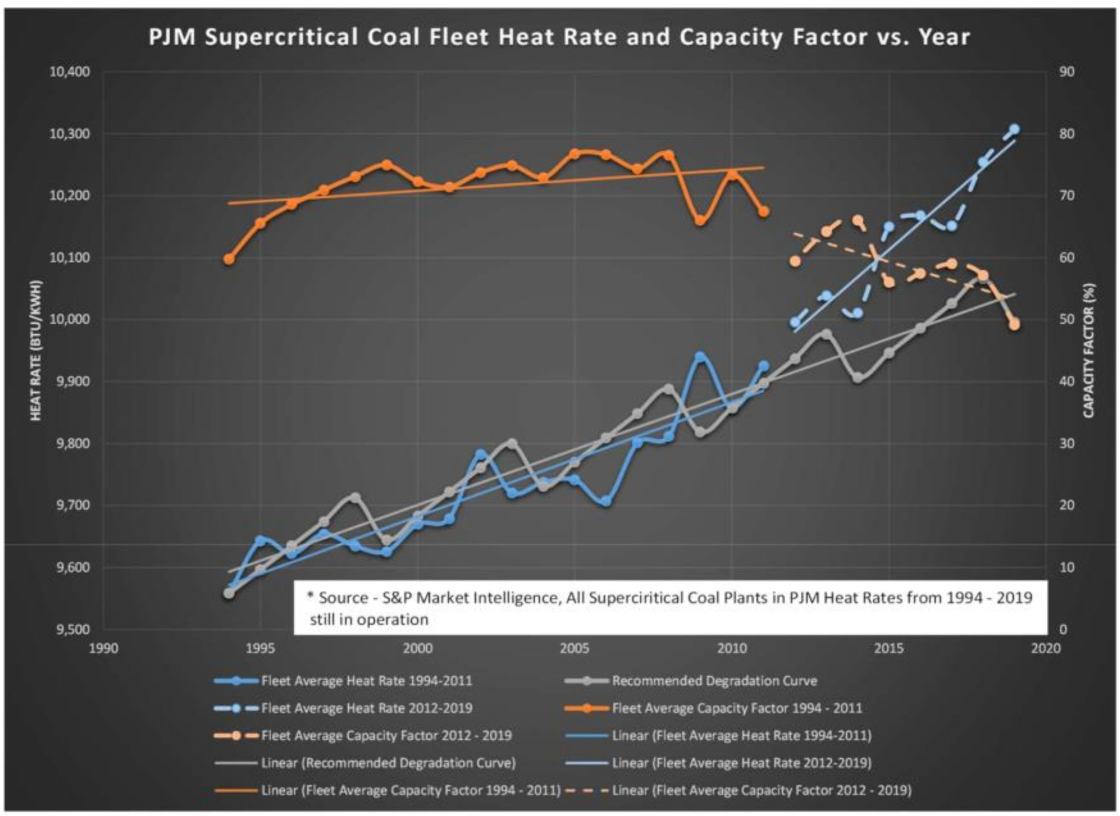
Heat Rate Degradation Support - LVP

Longview Power Heat Rate Degradation Support

Longview completed extensive analysis of peer supercritical coal fired plants in PJM Interconnection to determine historical actual degradation rates over time. Longview downloaded publicly available data from S&P Market Intelligence to complete the analysis. Annual heat rate data was downloaded for all current operating supercritical coal fired plants in the PJM Interconnection from 1994 to 2019 to provide a large sample size in same geographic region as Longview. This supercritical coal fleet is comparable to Longview Power with similar atmospheric conditions, fuel supply, market conditions, and basic plant design.

Longview analyzed the peer fleet (PJM coal fired operational supercritical units in operation since 1994) over the last 25 years as a basis for a recommended degradation rate. The recommended degradation limit curve utilized the average starting heat rate in year 1994 and escalated heat rate by the recommended degradation curve of 0.4% annual increase with a 0.7% reduction (recovery) due to major maintenance recovery every 5th year. This is represented in Figure 1 below; the result of the recommended degradation rate is less than the peer group over the last 25 years. The intent is to demonstrate an improved degradation rate over the historical demonstration of peer group. Please note that a single unit data set will exhibit wider variability than the larger population represented by a fleet of similar units due to averaging of numerous variables.

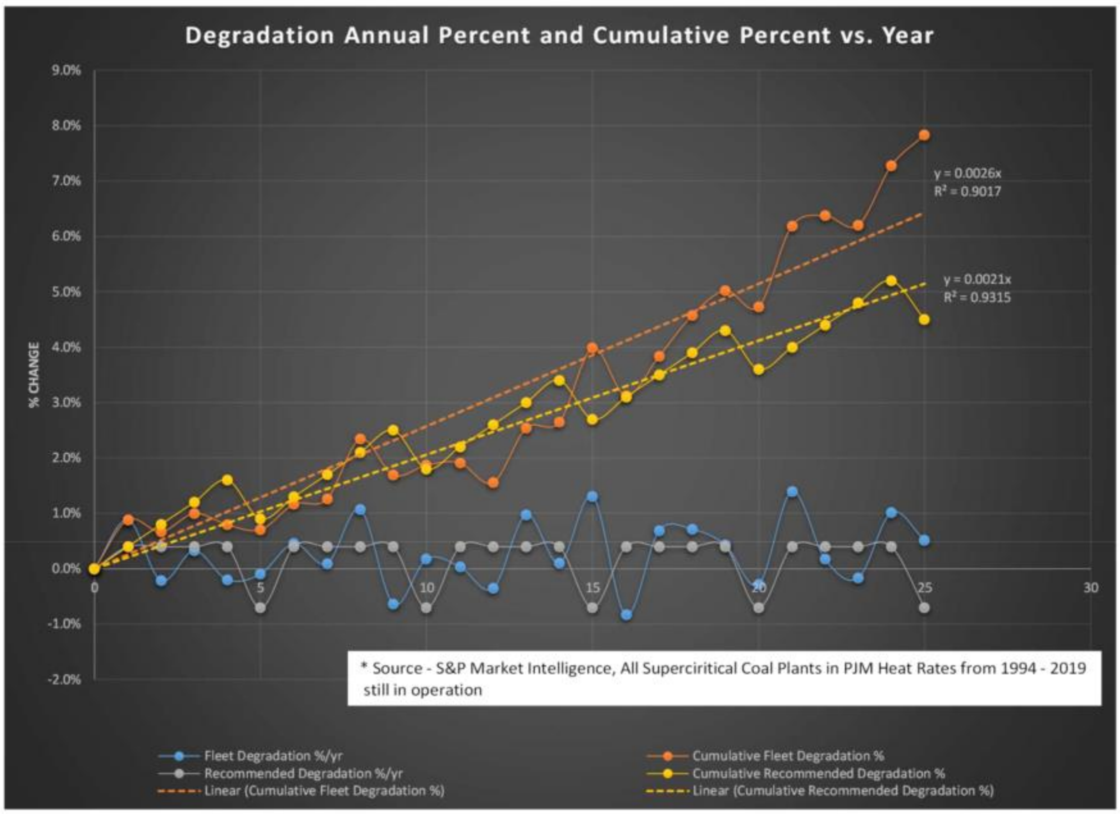
Figure 1:



There are two distinct time trends for the fleet data. First, from 1994 – 2011 there was an increasing trend in capacity factor that shows an increasing rate of change in heat rate. Starting around 2012, it is apparent that plant capacity factors for supercritical plants started to decline and the rate of increased heat rate increased at a much faster rate.

Figure 2 has the degradation displayed in terms of %/year and Cumulative % over a 25 year period based on fleet data starting in 1994 as year 0. As seen on the annual %/year over year trends you will see that the fleet has large swings year over year. The cumulative results show how the recommended degradation curve would yield greater than 3% better performance over a 25 year period.

Figure 2:



In conclusion, Longview recommends a 0.4% degradation rate annually with a 0.7% recovery every 5 years. This rate is supported by historical data from the peer group.

Longview - EPA ACE Study Results - Final 2020 08 11

Tuesday, August 18, 2020 8:20 AM

Longview - EPA ACE Study Results - Final 2020 08 11

FINAL

LONGVIEW UNIT 1 HEAT RATE STUDY

B&V PROJECT NO. 406009
B&V FILE NO. 14.410

PREPARED FOR

Longview Power

11 AUGUST 2020

BLACK & VEATCH

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1.0 Executive Summary

1.1 INTRODUCTION

Longview Power LLC asked Black & Veatch to support its efforts to analyze the potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355, "Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program. Proposed Affordable Clean Energy (ACE) rule." Longview Power operates Longview Unit 1, which is a coal fired electric generating unit (EGU), and specifically requested that Black & Veatch develop a high-level assessment report regarding four specific items:

- Variable frequency drive deployment for induced draft fans.
- Variable frequency drive deployment for boiler feed pumps.
- Potential internals upgrades for boiler feed pumps.
- Variable frequency deployment for forced draft fans (considered to be "targeted heat rate assessments" under ACE and a potential method for complying with CO_2 standards of performance).

To meet these goals, Black & Veatch prepared a high-level analysis of these heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emissions reduction (BSER). Estimates of HRI, annual carbon dioxide (CO_2) reduction, and a rough order of magnitude capital cost estimate have been developed for each alternative.

A comprehensive assessment of the technical and economic feasibility will not be provided in this effort but should be considered in a follow-on effort under a separate phase. Follow-on studies would consist of conceptual engineering to develop more accurate performance and cost estimates for the system(s) to better determine feasibility of the options evaluated at a high level in this study.

2.0 Existing Plant Characteristics

Table 2-1 shows the existing baseline full-load efficiency parameters for Longview Unit 1, along with net plant heat rate (NPHR) and CO_2 emissions rates. These data were gathered from the Longview Unit 1 PI Data and performance calculations and adjusted based on standard equations for consistency. The actual performance data is from June 25, 2019, from 13:00 to 17:00.

Table 2-1 Longview Unit 1 Baseline Actual Full Load Data

Unit	Gross/ Net (MW)	Net Turbine Heat Rate (NTHR) (Btu/kWh), Actual	Boiler Efficiency, HHV Basis (%)	NPHR (Btu/kWh)	Coal Burn Rate (ton/h)	Coal HHV (Btu/lbm)	CO_2 Emissions (ton/h)
Longview Unit 1	781.9/ 706.2	6,955	89.90	8,566	236.5	12,789	601.6

Btu/kWh: British thermal unit per kilowatt hour.
Btu/lbm: British thermal unit per pound-mass.
HHV: higher heating value.
ton/h: tons per hour.

The unit consists of a Foster Wheeler supercritical pulverized coal boiler with single reheat stage. Six pulverizers supply the boiler with coal, and combustion air is supplied by two forced draft (FD) fans. Two Ljungström combustion air heaters are used to heat primary and secondary air. Nitrogen oxides (NOx) control systems installed at the unit include low-NOx burners and a selective catalytic reduction (SCR) system. Particulate control is by a pulse jet fabric filter (PJFF). Sulfur dioxide (SO_2) control is by a wet flue gas desulfurization (WFGD) system. The baseline coal quality was based upon the weighted average of coal deliveries from January 2019 through March 2020 from the Cumberland FOB point.

3.0 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening was based on a high-level analysis of Longview Unit 1, as well as Black & Veatch's experience with similar projects. The projects depicted herein were selected from heat rate improvement (HRI) projects detailed by the EPA in its ACE proposal as BSER projects.

3.1 VARIABLE FREQUENCY DRIVE UPGRADES

VFDs function by controlling electric motor speed by converting incoming constant frequency power to variable frequency, using pulse width modulation. VFD upgrades for large electrically-driven rotating equipment provide many co-benefits, the largest of which is improved part-load efficiency and performance. This benefit is greatest at low load, and the more part-load and unit cycling that is done, the greater the benefit.

In addition to the reduced auxiliary power consumption, other benefits that are gained from the installation of VFDs on rotating equipment are as follows:

- Reduced noise levels around the equipment.
- Lower in-rush current during startups.
- Decreased wear on existing auxiliary power equipment.

Disadvantages of the installation of VFDs include the high capital cost plus a minimal amount of increased electrical equipment maintenance associated with the VFD system.

Output power signal quality and reliability of VFD equipment has increased significantly in the last 10 to 15 years, to the point that equipment from some manufacturers are approved for use, and have been installed, in nuclear power plants for critical equipment such as reactor coolant and recirculation pumps. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple insulation gate bipolar transistor power cells fail by automatically bypassing the bad cell, or cell(s), until an outage when repairs can be made. Additionally, output power signals meet Institute of Electrical and Electronics Engineers (IEEE) 519 1992 requirements eliminating the need for harmonic filters.

VFD installation steps are typically as follows:

- Replace the existing rotating equipment coupling with resilient elastomeric block-shaft couplings to ensure no electrically induced torsional forces are transferred to the fan rotor. This means the existing equipment must be de-coupled from the motor and then realigned with the new coupling.
- Make upgrades to the lube oil system as necessary.
- Install new VFD enclosure foundations.
- Install new VFD enclosures and heat exchangers.
- Replace the power supply cables between existing switchgear to the new VFD enclosure. Install new cables from the VFD enclosure to the motor.

- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements. The air-cooled VFD equipment can further reduce equipment installation and maintenance costs.

The logistics of these types of upgrades are typically as follows:

- Engineering design and specification development: 2 months.
- Bid process: 1.5 months.
- Contract negotiations: 1.5 months.
- Drawing submittal and reviews: 2 months.
- Lead time for equipment: 6 to 12 months.
- Outage time: approximately 1 month.

The rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps and the large draft fans for handling combustion air and flue gas (forced draft and induced draft fans).

3.1.1 Boiler Feed Pumps

Based on available information, Longview boiler feed pumps (BFP) auxiliary power consumption benefit is estimated to be negligible at full load (782 MW gross) and 3.8 MW at low load (475 MW gross).

Refer to Figures 3-1 and 3-2, which illustrate the current BFP train operation and future variable speed operation with the addition of VFDs. The VFD analysis allowed a reduction of pump speeds by 4 percent at full load and 29 percent at low load. These pumps operate near their highest efficiency point at full load, thus there is only savings potential at low load, even with the fluid drives still in place. Given the high capacity factor of the unit, the practical annual potential heat rate improvement is low (0.19 percent), especially given the high cost of the VFDs.

The estimated furnish and erect price for a VFD system for the Longview BFPs includes VFD, VFD enclosure, enclosure foundations, coupling, new power cabling and any new raceway required, engineering, installation, and contingency. Limited available space immediately around the rotating equipment would not affect the installation of VFD systems as the equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the VFD.

VFD Deployment for BFPs

Total Installed Capital Cost:	$9.9 million for three pumps
Auxiliary Power Reduction:	Full load (782 MW gross): Negligible Low load (475 MW gross): 3.9 MW
Heat Rate (Efficiency) Improvement:	Full Load (782 MW gross): Negligible Low Load (475 MW gross): 0.5 percent
Estimated Additional Annual O&M Cost:	$9,000 for three pumps

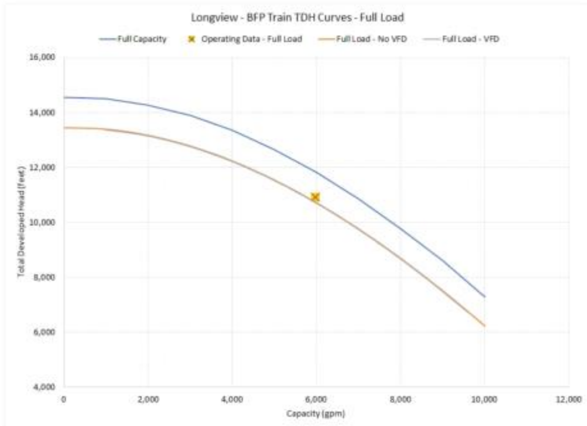

Figure 3-1 Boiler Feed Pump Train Curves - Full Load Variable Frequency Speed Comparison

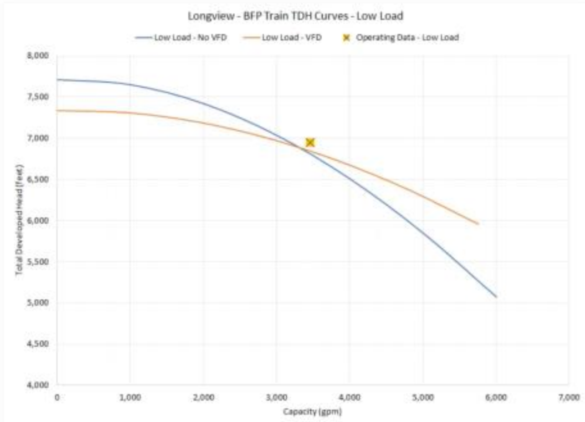

Figure 3-2 Boiler Feed Pump Train Curves - Low Load Variable Speed Comparison

Note as well that no analysis was conducted on the potential for utilizing the booster pump in any auxiliary manner to improve BFP utilization, as that was outside the scope of this study.

Overall, the estimated benefit from implementing VFD drives on the boiler feed pumps, compared to the estimated cost, indicates that from the standpoint of implementing the BSER for Longview this option does not have statistically significant merit. Therefore, this option is not recommended for compliance.

3.1.2 Large Draft Fans

Longview Unit 1 has forced and induced draft air fans that will be evaluated in this study. The forced draft and induced draft fans are currently axial-type with single speed motors and controlled by modulating blade position (variable blade pitch controls).

3.1.2.1 Forced Draft Fans

According to the available information and operating data the Longview Unit 1 forced draft (FD) fan, auxiliary power consumption would be estimated to decrease by 410 kW for two fans at full load (782 MW gross) and 220kW at low load (475 MW Gross). Refer to Figure 3-3 and Figure 3-

4 illustrating the current FD fan operation with variable blade pitch controls and future variable speed operation with VFDs.

Axial fans with blade modulation operate at a very efficient load profile, reducing the benefits associated with VFD operation. Additionally, following installation, the VFD may not operate at the most efficient speed to avoid the stall line of the axial fan. Also, control of the fan following VFD installation will be complicated by the both the speed control and blade angle control.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,472,000 for two fans
Auxiliary Power Reduction:	Full load (782 MW gross): 0.41 MW
	Low load (475 MW gross): 0.22 MW
Heat Rate (Efficiency) Improvement:	Full load (782 MW gross): 0.058 percent
	Low load (475 MW gross): 0.052 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit

The estimated furnish and erect price for a VFD system for the Longview Unit 1 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling, and any new raceway required engineering, installation, and contingency. If limited space is available immediately around the rotating equipment, this will not affect the installation of VFD systems because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

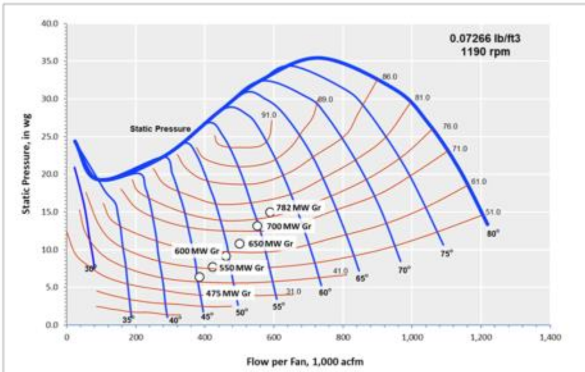

Figure 3-3 Longview Unit 1 FD Fan Operation – Variable Blade Pitch Control

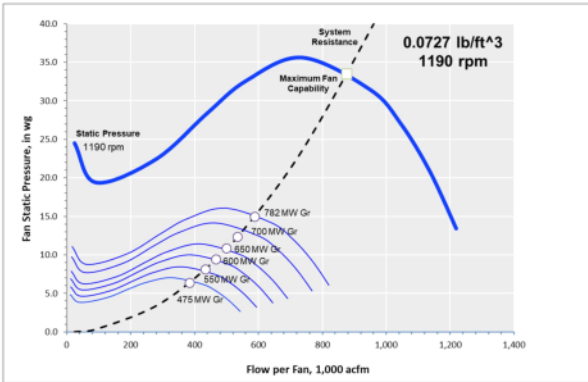

Figure 3-4 Longview Unit 1 FD Fan Operation – Variable Speed with VFDs

Overall, the estimated benefit from implementing VFD drives on the forced draft fans, especially when compared to the estimated cost, indicates that from the standpoint of implementing the BSER for Longview this option does not have statistically significant merit. Therefore, this option is not recommended for compliance.

3.1.2.2 Induced Draft Fans

According to the available information and operating data, the Longview Unit 1 induced draft (ID) fan auxiliary power consumption benefit is estimated to be negligible for two fans at full load (782 MW gross) and 120 kW at low load (475 MW gross). Refer to Figure 3-5 and Figure 3-6 illustrating the current ID fan operation with variable blade pitch control and future variable speed operation with VFDs.

Axial fans with blade modulation operate at a very efficient load profile, reducing the benefits associated with VFD operation. In this case of this application, the VFD may result in less efficient operation if used to reduce speed at full load. Following installation, the VFD may not operate at the most efficient speed to avoid the stall line of the axial fan. Also, control of the fan following VFD installation will be complicated by the both the speed control and blade angle control.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$3,650,000 for two fans
Auxiliary Power Reduction:	Full load (782 MW gross): Negligible Low load (475 MW gross): 0.12 MW
Heat Rate (Efficiency) Improvement:	Full load (782 MW gross): Negligible Low load (475 MW gross): 0.028 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit

The estimated furnish and erect price for a VFD system for the Longview Unit 1 ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling, and any new raceway required engineering, installation, and contingency. If limited space is available immediately around the rotating equipment, this will not affect the installation of VFD systems because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

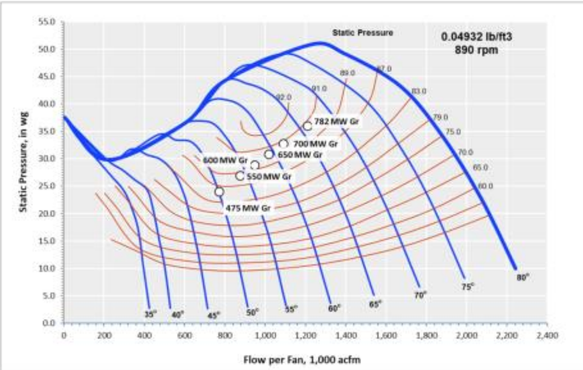

Figure 3-5 Longview Unit 1 ID Fan Operation – Variable Blade Pitch Control

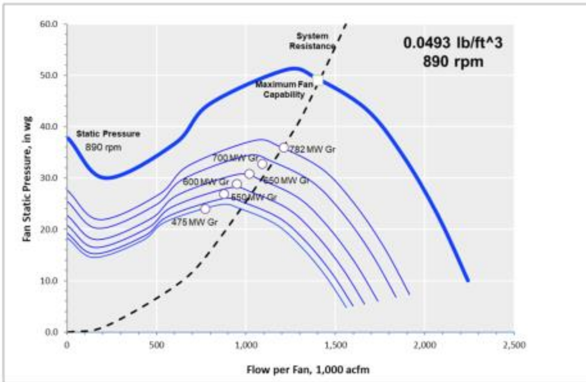

Figure 3-6 Longview Unit 1 ID Fan Operation – Variable Speed with VFDs

Overall, the estimated very limited benefit from implementing VFD drives on the induced draft fans, especially when compared to the estimated cost, shows that from the standpoint of implementing the BSER for Longview this option does not have statistically significant merit. Therefore, this option is not recommended as a method for compliance.

3.2 BOILER FEED PUMP UPGRADES, REBUILDING, OR REPLACEMENT

The purpose of this project would be to report on the current design of the boiler feed pumps (BFPs) and potential technology upgrades that could improve the heat rate (other than routine maintenance activities).

3.2.1 Boiler Feed Pumps

The plant has three 50 percent boiler feed pumps trains, each comprised of a single speed booster pump and motor, a VOITH hydraulic geared coupling, and a main boiler feed pump. The booster pumps are KSB model KRHA 300/660. The main boiler feed pumps are KSB model CHTD 7/7 (seven stage), horizontal, barrel-type pumps with radial impellers and single-entry. Each pump has a rated capacity of 6,550 gallons per minute (gpm), operating pressure of 4,520 pounds per square inch gauge (psig), operating temperature of 372 °F, total developed head (TDH) of 11,346 psig, and developed pressure of 4,345 psi at 5,072 revolutions per minute (rpm).

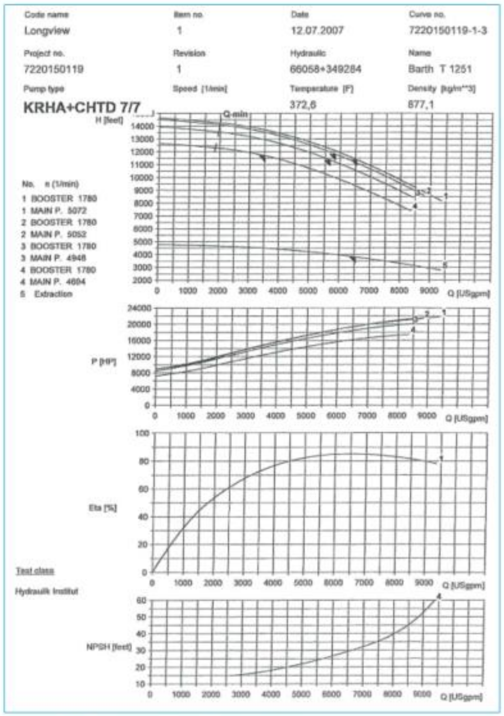

Figure 3-7 **Boiler Feed Pump Performance Curves**

SIEMENS

Specification for Boiler Feedwater Pumps

Document No.:	**USA741-XW01-LAC-4601-01**
Project:	**Longview**
Index / Date:	01 / June 25, 2007
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APPENDIX B1
PUMP DESIGN DATA SHEET

Operating, system and Guarantee Data			VWO	Bypass	ASME Master Stamping	ASME SV Open		Inter-stage
Designation		**Units**						
System Data	Number installed	[-]			3			
	Number in operation	[-]			2			
	Plant Load Service	[%]			50%			
	Medium	[-]			Feedwater			
	pH-value Medium at 23 °C	[-]						
	Solid Content / Water Quality	[mg/m³]						
	Max.Allow. Working Pressure (MAWP) suction side	[psig]			262			
	MAWP discharge side	[psig]			5925			
	Pressure Nominal DIN / ANSI-Class							
	Test Pressure (Gauge)	[psig]						
	Temperature for pressure test	[°F]			room temperature (min. 20 [°C])			
	Max. Allow. Working Temp.	[°F]			410			
	Max. allowable shutoff head *)	[ft]			14,749.8			
	Max. allowable min flow	[gpm]						
	Max. flow	[gpm]						
	*) inclusive all fabrication tolerances							
Operating Data:	Operating Temperature	[°F]	370.5	372.6	372.7	372.7		370.5
	Density	[lbm/ft³]	56.0	55.9	56.0	56.0		56.0
	NPSH available (refered to pump suction nozzle)	[ft]	50.6	49.9	50.4	52.3		50.6
Operating Pressure (abs)	Inlet	[psia]	175.0	175.0	176.0	177.0		175.0
	Intermediate Stage	[psia]						1480.0
	Main Stage	[psia]	4510.0	4520.0	4554.0	4638.0		4510.0
Flow Rate	Inlet	[gpm]	6,367	6,550	6,367	3,826		6,367
	Intermediate Stage	[gpm]	693		523	309		693
	Main Stage	[gpm]	5,674	6,550	5,844	3,517		5,674
Developed Head and Pressure	Intermediate Stage	[ft]						3,415.0
	Intermediate Stage	[psid]						1,305
	Main Stage	[ft]	11,327	11,346	11,777	11,673		11,327
	Main Stage	[psid]	4,335	4,345	4,509	4,461		4,355

Siemens AG - Power Generation (PG)

Figure 3-8 Boiler Feed Pump Design Data Sheet

The full load operating set from July 25, 2019 has the Boiler Feed Pump 1 operating at 4,860 rpm with a discharge flow rate of 5,970 gpm and TDH of 10,912 feet. With a pump speed of 4,860 rpm and the full load operating flow rate the design curve indicates a TDH of 10,739 feet. The pump lies slightly above its curve, suggesting that this pump is in good operation condition and no significant degradation has occurred. As a result, technology upgrades to the boiler feed pump internals are not recommended as a viable method for heat rate improvement. It is only recommended that that the regular program of maintenance and as-needed repair continue.

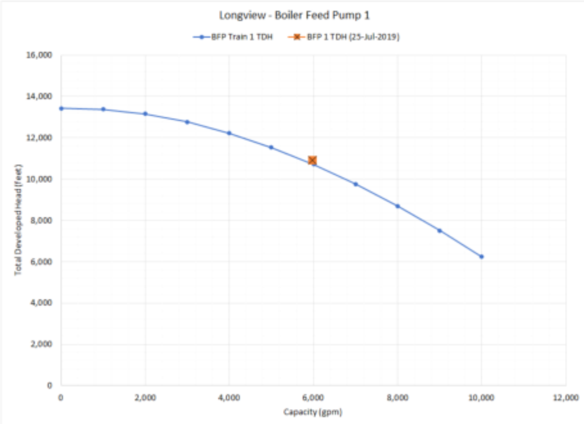


Figure 3-9 Boiler Feed Pump 1 Performance

The full load operating set from August 16, 2019 has the Boiler Feed Pump 2 operating at 4,866 rpm with a discharge flow rate of 5,924 gpm and TDH of 10,961 feet. With a pump speed of 4,866 rpm and the full load operating flow rate the design curve indicates a TDH of 10,806 feet. The pump lies slightly above its curve, suggesting that this pump is in good operation condition and no significant degradation has occurred. As a result, technology upgrades to the boiler feed pump internals are not recommended as a viable method for heat rate improvement. It is only recommended that that the regular program of maintenance and as-needed repair continue.

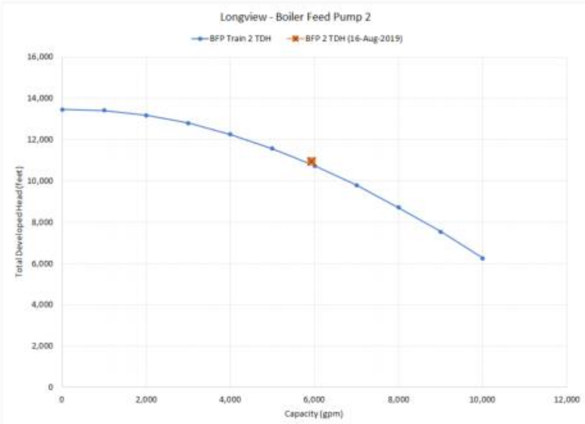


Figure 3-10 Boiler Feed Pump 2 Performance

The full load operating set from July 25, 2019 has the Boiler Feed Pump 3 operating at 4,838 rpm with a discharge flow rate of 5,989 gpm and TDH of 10,843 feet. With a pump speed of 4,838 rpm and the full load operating flow rate the design curve indicates a TDH of 10,606 feet. The pump lies slightly above its curve, suggesting that this pump is in good operation condition and no significant degradation has occurred. As a result, technology upgrades to the boiler feed pump internals are not recommended as a viable method for heat rate improvement. It is only recommended that that the regular program of maintenance and as-needed repair continue.

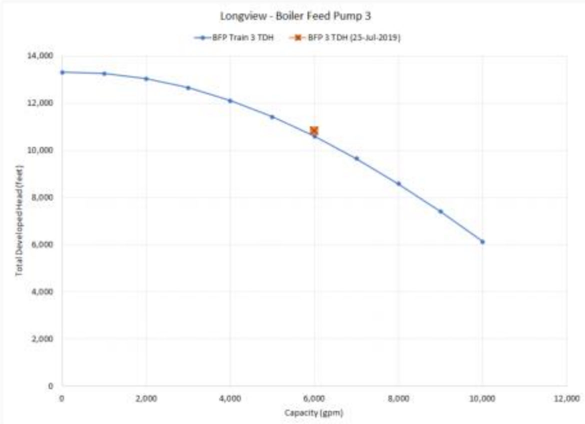


Figure 3-11 Boiler Feed Pump 3 Performance

3.3 IMPROVED OPERATIONS AND MAINTENANCE PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to the following two areas of focus: HRI training, and on-site appraisals for identifying additional HRIs. This section is provided as a generic reference to show potential based upon Black & Veatch experience, and is not intended to apply specifically to Longview.

3.3.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training, which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified through years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared toward operators and engineers.

Total Installed Capital Cost:	$15,000/class (could cover multiple units and plants).

Heat Rate (Efficiency) Improvement:	Unknown, although improved O&M practices at peer coal fired EGUs have claimed to result in NPHR improvements of 0.1 to 0.5 percent in the first year of implementation.

3.3.2 On-Site Heat Rate Appraisals

This item, which is mentioned as a BSER in the EPA ACE proposal, is left open to interpretation and indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost or HRI. On-site heat rate appraisals are often conducted via detailed assessment of controllable losses, especially those that can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant O&M personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of HRI projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly HRI and 4 MW capacity improvement.
- An audit of terminal temperature difference and drain cooler approach temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50 percent of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5 percent) and a net capacity loss of 2.5 MW.
- Testing of mill dirty-air flows and coal flow balances at one power plant found that by rebalancing the flows on four mills to bring the coal and air flow deviation to within +/- 10 percent (compared to the +/- 30 percent it formerly operated), coal unburned carbon heat losses decreased by 0.5 percent, which directly translated to an HRI of 0.5 percent. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1 percent (and a corresponding improvement in furnace wall tube life).
- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage caused by debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were seven of the coals unprofitable to burn, burning the worst coal resulted in a

heat rate loss of more than 2 percent. Moreover, this coal was responsible in whole or in part for most of the plant de-rates caused by high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis because of the increased number of starts and stops from fouling-related outages.

- A long-term analysis of plant continuous emissions monitoring system data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending two different coals to meet the plant SO_2 limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating to 0.6 percent on an annual basis.

Heat rate assessment is an evermoving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall HRI.

3.4 GROSS VERSUS NET HEAT RATE IMPROVEMENT

The NPHR can be determined by the input/output method, whereby the equation is as follows:

$$NPHR = \frac{Total\ Fuel\ Heat\ Input, Btu/h}{Net\ Generation, kW}$$

The resulting calculation is whence is derived the mixed US/SI units of Btu/kW*h. Correspondingly, the gross plant heat rate (GPHR) is as follows:

$$GPHR = \frac{Total\ Fuel\ Heat\ Input, Btu/h}{Gross\ Generation, kW}$$

While technically correct, this simple form of plant heat rate equations hides the fact that the NPHR is actually the product of the efficiencies of the following three primary energy conversion processes within a Rankine-cycle power plant:

- Boiler efficiency, which is where fuel energy is converted to steam energy.
- Turbine efficiency, which is where steam energy is converted to rotational energy.
- Electrical use efficiency, which is how efficiently the plant utilizes the rotational energy to generate saleable electricity.

Thus, a better equation that illustrates these three energy conversion processes is known as the loss method equation:

$$NPHR = \frac{Net\ Turbine\ Heat\ Rate, \frac{Btu}{kW*h}}{Boiler\ Efficiency\ (fraction) * \frac{Net\ Generation, kW}{Gross\ Generation, kW}}$$

Correspondingly, since the concern for the GPHR is the gross generation, the GPHR heat loss equation is as follows:

$$GPHR = \frac{Net\ Turbine\ Heat\ Rate, \frac{Btu}{kW*h}}{Boiler\ Efficiency\ (fraction) * 1.0}$$

Therefore, the primary difference between the GPHR and NPHR is how one accounts for station service (auxiliary power). Take, for example, the case of a unit with the following characteristics:

- Gross output: 400 MW
- Net output: 370 MW
- NTHR: 8,000 Btu/kWh
- Boiler efficiency: 88 percent

By utilizing the previous equation for NPHR, the result for this unit would be as follows:

NPHR = 8,000 / ([88/100]*[370/400]) = 9,828 Btu/kWh

And the GPHR for this unit would be as follows:

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

If it is assumed that this unit deploys VFDs for its main fans and reduces the station service by 2 MW, the net generation will increase at the same gross output. Thus, the new characteristics of the unit are as follows:

NPHR = 8,000 / ([88/100]*[372/400]) = 9,775 Btu/kWh

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

In this case, the NPHR has shown an improvement of 53 Btu/kWh (about 0.5 percent), but the GPHR reflects no such benefit.

Because of its neglect of changes in station service, utilizing the GPHR measurement, therefore, has the risk of invalidating the following technologies:

- Air heater and duct leakage control.[1]
- VFD motor deployment.
- Many improved O&M practices.
- BFP upgrades for electric BFPs.

The case where the gross heat rate would be the better heat rate metric for a coal fired EGU would be where emissions controls for pollutants such as NO_X, SO_2, etc., must be installed or upgraded on a unit to meet more stringent emissions limits. Taking again our hypothetical unit, if the unit must install an SCR system that requires 5 MW of additional station service, the gross heat rate would not be impacted, but the net heat rate would worsen from its baseline value of 9,828 Btu/kWh to the following:

NPHR = 8,000 / ([88/100]*[365/400]) = 9,963 Btu/kWh

In other words, a 1.37 percent worsening of NPHR. This could be problematic in cases where a unit's performance standard was based on net measurement and an emissions control addition resulted in an increased net heat rate that was not contemplated or accounted for when the standard was set.

[1] Care must be taken to distinguish between air heater heat transfer surface upgrades, which will increase the boiler efficiency, and air heater leakage reduction, which will reduce the station service. In the first case, increasing the boiler efficiency improves both the NPHR and GPHR. In the second case, reducing the station service only improves the NPHR. The proposed rule is also not clear on whether leakage reduction projects are considered to

4.0 Performance and Carbon Dioxide Reduction Estimates

High level plant performance estimates were used to estimate the average annual CO_2 reduction. These performance benefits are summarized in Appendix B, Tables B-1 and B-2. It should be noted that some projects will have overlapping performance impacts and benefits, so that the overall net benefit for a series of projects considered together will likely differ from the sum of the individual project benefits listed in Tables B-1 and B-2.

The annual CO_2 reductions shown in Table B-1 were estimated from the PI data provided by Longview and assumed a baseline 76.7 percent net capacity factor. The 76.7 percent net capacity factor was retrieved from the S&P Global database as the average value from 2015-2019, inclusive. In addition to PI data, the existing Electric Power Research Institute Vista model of Longview was utilized to confirm and predict the annual average net plant heat rate values across the load curves.

Table 4-1 Basis for Current CO_2 Reduction Estimates – 76.7 Percent Net Capacity Factor

Gross/Net Capacity (MW)	Net Capacity Factor (%)	Average Annual NPHR (Btu/kWh)*	Fuel Heat Input (MBtu/y)*	LBM CO_2/ MBtu (HHV)*	Annual CO_2 (tons/y)*
781.9/ 706.2	76.7	8,596	41,360,298	200.4	4,144,410

*Note that this differs from Table 2-1 because an annual average value is used, rather than full load value.

The annual CO_2 reductions over the next 5 years shown in Table B-2 were projected using estimated values provided by Longview personnel. These values ranged from 85 to 92 percent, with Longview giving an average value of 87 percent. Gross and net capacity were unchanged, although the average annual NPHR did vary because of the difference in the net capacity factor.

Table 4-2 Basis for Future CO_2 Reduction Estimates – 87.0 Percent Net Capacity Factor

Gross/Net Capacity (MW)	Net Capacity Factor (%)	Average Annual NPHR (Btu/kWh)	Fuel Heat Input (MBtu/y)	LBM CO_2/ MBtu (HHV)	Annual CO_2 (tons/y)
781.9/ 706.2	87.0	8,577	46,491,199	200.4	4,658,560

Where:

Fuel Heat Input [MBtu/y] =

Net Capacity [MW] * 1,000 kW/MW * Capacity Factor [%] * 8,760 h/y * NPHR [Btu/kWh, HHV]/ (1,000,000 Btu/MBtu)

Annual CO_2 Production [tons/y] =

Fuel Heat Input [MBtu/y] * CO_2 Production Rate [lbm/MBtu of Fuel Burned]/ (2,000 lbm/ton)

Appendix A. Abbreviations and Acronyms

°F	Degrees Fahrenheit
ACE	Affordable Clean Energy (Plan)
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
FD	Forced Draft
GPHR	Gross Plant Heat Rate
gpm	Gallons per Minute
h	Hour
HHV	Higher Heating Value
HP	High-Pressure
HRI	Heat Rate Improvement
ID	Induced Draft
IEEE	Institute of Electrical and Electronics Engineers
IP	Intermediate-Pressure
kW	Kilowatt
kWh	Kilowatt-hour
lbm	Pound-Mass
LP	Low-Pressure
MBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NO_x	Nitrogen Oxides
NPHR	Net Plant Heat Rate
O&M	Operations and Maintenance
PI	Plant Instrumentation
rpm	Revolutions per Minute
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
TDH	Total Developed Head
ton/h	Tons per hour
VFD	Variable Frequency Drive

Vista	The EPRI Vista fuel quality impact analysis program, which is used to model this unit.
Y	Year

Appendix B. Capital Cost and Performance Estimates

Table B-1 Preliminary EPC Capital Cost Estimate (in 2020 Dollars) and First Year Performance Benefits (Current Net Capacity Factor – 76.7 Percent)

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/ton/y)	Average Annual O&M Cost Impact**
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	9,900	0.19	16.4	78,998	7,916	1,250.66	Low
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,472	0.06	4.8	23,041	2,309	1,070.70	Low
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	3,650	0.01	0.9	4,424	443	8,233.96	Low
Boiler Feed Pump Upgrades, Rebuilding, Or Replacement	Boiler Feed Pumps	NA	NA	NA	NA	NA	NA	NA

Table B-2 Preliminary EPC Capital Cost Estimate (in 2020 Dollars) and First Year Performance Benefits (Future Net Capacity Factor – 87.0 Percent)

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/ton/y)	Average Annual O&M Cost Impact**
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	9,900	0.19	16.4	88,798	8,898	1,112.63	Low
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,472	0.06	4.8	25,899	2,595	952.53	Low
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	3,650	0.01	0.9	4,973	498	7,325.20	Low
Boiler Feed Pump Upgrades, Rebuilding, Or Replacement	Boiler Feed Pumps	NA	NA	NA	NA	NA	NA	NA

Long Term Equipment Related Heat Rate Variability 45CSR44 -LVP

Tuesday, August 18, 2020 8:19 AM

Long Term Equipment Related Heat Rate Variability 45CSR...

Long Term Equipment Related Heat Rate Variability

There are a significant number of scenarios in which an unexpected unavoidable equipment failure or condition monitoring finding may require a critical piece of equipment to be taken out of service. Such a scenario would be expected to have an impact on heat rate and efficiency and economic viability of the generating unit. The impacts of these equipment failures can be reasonably categorized and estimated and are therefore sought to be contemplated in formulating Affordable Clean Energy rule requirements.

One such example is the Low Pressure (LP) Turbine L-0 blading. The L-0 blading on an LP Turbine is the final stage of converting steam energy into mechanical energy to be converted to electrical energy at the generator. These blades are very long in order to efficiently convert as much energy as possible. This design creates significant stress on the blades due to forces placed on them. Additionally, since this is the last stage of blading, the steam has started to transition into saturation temperatures becoming wet steam; creating an ongoing erosion issue on the leading edges of blades.

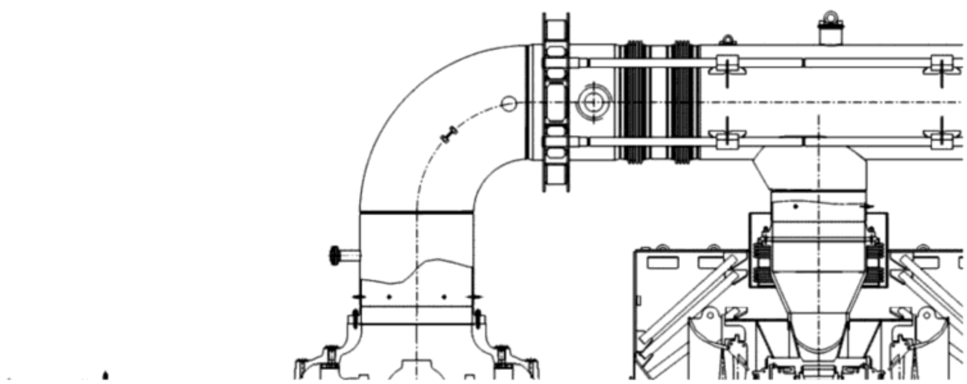


Figure 1: Longview Power Steam Turbine Overview

As illustrated in Figure 1, the L-0 blading is the last row of blades and they are the largest blades in system.

L-0 blading (the last rotating row) in LP Turbines has been an ongoing industry wide design and reliability issue for equipment manufacturers and plant engineers for many years. This row experiences a very unique range of operating conditions that place significant stresses on the material. Longview, as well as most facilities, have an extensive advanced non-destructive examination technologies program to monitor the condition of the blading. Longview utilizes these advanced examinations approximately every 25,000 hours of operation (approximately every 3 ½ years) or after a turbine trip with a loss of condenser vacuum due to additional significant stresses on the LP Turbine blading. This effort and expense is completed to proactively identify an issue in a very early stage that can be corrected or mitigated prior to a complete failure event.

Even with these proactive measures in place, there is a risk of turbine blade failures that would allow for continued, albeit less efficient, facility operation during extensive repairs. A row of L-0 blading is approximately $1MM material cost per row (2 or 4 rows would be needed) and a 1 year lead time due to the size of forgings and specialty materials and machining required. In the case that requires replacement of the L-0 blading (two rows per affected rotor) there would be an approximate 15 - 30% MW load loss and an 8% - 16% impact to unit efficiency. This temporary measure will allow continued operation and preservation of some revenue thus maintaining the business until the parts can be supplied. Replacement of L-0 blades would require a 5-6 week long outage. If some form of regulatory relief mechanism (i.e. depending on severity, the level 2 limit or some form of negotiated "Emergency" limit) were not in place, this unavoidable high impact scenario could result in having to run the unit out of compliance for well over a one year time period.

A loss of L-0 is just one example of a situation where a unit such as Longview would still be able to make high MW load but at a significant impact to efficiency. There are other cases such as a loss of circulating water pump, loss of condenser, cooling tower loss, or loss of HP or LP heaters.

The case of failure of circulating water pump, portion of the cooling tower, or portion of the condenser would have minimal impact on the amount of net generation the unit could produce but each of these scenarios would have a 7 – 10% impact to efficiency due to the increased back pressure on the turbine in the condenser. Even with best-in-class O&M practices and spare part readiness there are failure instances, such as that of a condenser and/or the circulating pump that necessitate relief to the degree of a Level 1 to allow the unit to continue operation thus preserving economic viability while repair plans and parts are expedited.

In conclusion, there are equipment failures that can be reasonably managed via the O&M best practice BSER; however, there are real scenarios that even with best-in-class O&M BSER practices, a reasonable operator acting prudently cannot avoid. Some regulatory flexibility is necessary to account for such unavoidable issues until they can be repaired and corrected.

LVP ACE Rule Justifications for Fuel and Calc 2020-07-30

Tuesday, August 18, 2020 8:17 AM

LVP ACE Rule Justifications for Fuel and Calc 2020-07-30

LVP ACE Rule Justifications & Language

Fuel Change Triggering Re-Evaluation

Should a significant fuel change be warranted at the discretion of the company or as a result of a supplier change and/or issue, and the EGU undergoes a fuel change, the CO_2 Standard of Performance would be re-evaluated and potentially adjusted in the event the fuel change is to a degree that affects compliance. Parameters that could potentially change due to a fuel change, and could affect heat rate and/or CO_2 performance are but are not limited to:

- Heat Content
- Sulfur
- Ash
- Moisture
- Chlorine
- Nitrogen

In the event of a significant fuel change, Longview Power would notify WVDEP DAQ of the change, as well as provide analytical data supporting the need for a re-evaluation of the CO_2 standard. At such time, DAQ would review the provided data, and continue discussions as necessary, resulting up to and including recalculation of the CO_2 Standard of Performance levels on a per bin basis based on the new fuel characteristics. The CO_2 Standard or Performance and associated permit should in no way limit the ability of the company to secure and consume fuels beyond those currently utilized.

Standard of Performance / Compliance Target Calculation

Load Bin Structure

Load Bin	Load Range (MWHN)
0	<313
1	313-407
2	407-501
3	501-595
4	595-689
5	689-783

Terms and Operation

Normal Operation – "Level 1", Calculated per load bin based on Rolling 12 month highest average + 2 standard deviations

Issues Arise – "Level 2", 110% of Level 1 standards, per bin

Emergency – “Emergency” Declaration

Baseline compliance limit – Utilizing 2016-2020 Q2 data, develop load bins and calculate each bin standard based on maximum rolling 12 month average + 2 SD.

Calculation of annual compliance limit – Calendar year compliance limit, break unit data into load bins and calculate performance based on time-weighted average of load bins the unit ran in for reporting year.

Based on % run time in each bin, per bin standards of performance would be used to create a compliance limit through the use of a time-weighted average based across 10 bins (L1 Bins 1-5 and L2 Bins 1-5), calculated using net generation (MWHN)

Bin 0, SUSD, calculated independently, utilizing gross generation (MWHG)

Compliance

For each prior calendar year, the unit would sum the total CO_2 lbs and divide by the total net generation in MWHN, thereby calculating the annual CO_2 performance in lbs/MWHN.

After year 0, baseline calculation, the degradation schedule would be applied to each bin going forward in time.

LVP ACE Supplemental Narrative 2020-08-12 rev2

Tuesday, August 18, 2020 10:42 AM

LVP ACE Supplemental Narrative 2020-08-12 rev2

Standard of Performance Calculation and Statistical Analysis

When assessing the Longview CO_2 data, several areas become readily apparent and affect the appropriate methods for calculating the CO_2 Standard of Performance. Standard Deviation (SD or the measure of the "spread" of a data set around its mean value) is a concept integral to this analysis and allows for a proper understanding of the sample data, as well as assisting in predicting future performance with an appropriate degree of uncertainty. To further explain:

1) The unit has spent the vast majority of its runtime (>92% from 2016 through 2020) in Bin 5 at generation loads greater than 689 MW (Gross). The data in Bin 5 is of high quality with a large number of samples held tightly around the mean, thereby very accurately reflecting the units CO_2 performance in that bin. An indicator of this data quality is through the use of the Sample Standard Deviation which measures the typical distance between each data point and the mean (average). In bin 5, this SD is very low so by incorporating the calculated mean, as well as 2 times the standard deviation, the Bin Limit (Mean + 2x SD) is a very accurate representation of where most of the actual has, and future data will fall, based on load. Statistically speaking, 95% of the data will fall within 2 standard deviations of the mean.

2) For Bins 1-4, 313 MWG through 689 MWG, a challenge presents itself, based on the fact that they account for less than 7% of the units run hours. There is a significant lack of data points, and the unit is generally moving load as quickly as possible to achieve maximum gross generation which is reflected by Bin 5. Based on this situation, the average is of a lesser certainty calculation than what was seen in Bin 5, and demonstrates a higher variability due to transient generation load as well as a lower number of data points. This results in a higher standard of deviation in each of these load bins than in bin 5. However, due to the significance of standard deviation, the idea of the mean + 2 SD is still relevant and applicable. The data in these bins is less evident, and the Bin Limit calculations (Mean + 2 SD) still give reliable and meaningful results as 95% of the data still fit within this limit.

3) The Longview unit has demonstrated in an appropriate manner that all BSER or equivalent technologies have been implemented, and both heat rate and CO_2 performance is currently meeting the requirements set forth under the ACE Rule. Based on these demonstrations, no further improvements are required or anticipated for either heat rate or CO_2 rate.

Based on both the Bin 5, and the Bin 1-4 discussion, the concept of Sample Standard Deviation is both valuable, and appropriate, in predicting future unit performance based on the sample data from 2016 through 2020 Q2. Additionally, since the unit has demonstrated implementation of all BSER (or equivalent), no performance enhancement is required or anticipated. This standard deviation accounts for normal operational variances and measurement uncertainty. Measurement uncertainty alone can have a much larger acceptable variation than 2 SD in current data. Therefore, the 2 SD approach is appropriate to set limits that can be met via current unit operation, and that is indeed the case for Bins 1-5 utilizing this method of analysis and calculation.

Degradation Basis and Influence of Capacity Factor

When looking at unit degradation over time, fleet performance is a key indicator of what may be expected in terms of rate of decay, and in turn, CO_2 and heat rate performance degradation. While there are many factors that can influence this degradation, two critical ones via mechanical and thermal stress and in turn lower unit efficiency. These may be recovered in part through maintenance activities and repair/replacement of critical systems. Another factor that greatly influences unit degradation is the Capacity Factor (CF) of the unit. As the units shift from initial base-loaded operation, to more and more load swings, lower steady state loads, and even approaching peaking unit operation (many startup/shutdown events), the lower efficiency inherent in units (as demonstrated by each units unique "Heat Rate Curve") at these lower loads and changing loads, can reflect itself as degraded performance. While it may seem that capacity factor influence may be readily filtered out from the unit degradation due to thermal and physical stresses and associated inefficiencies, it actually cannot. Increased SUSD operations, more and more radical load shifts, great operation at lower loads, all of these increase the physical stress, fatigue, creep, corrosion, and wear thus causing unit degradation above and beyond what may be accounted for in the observed unit efficiency reductions when operating in lower load bins.

Performance recovery after major outage work has been predicted for the Longview unit, and is reflected in the degradation/recovery rate. These outages will occur in future years and while some level of performance enhancement is expected, it may not be analytically quantified at this time, due to a lack of data. It does need to be noted that not all outage/maintenance work will sufficiently recovery all damage as there are practical physical and economic limits to repair and replacements at every overhaul cycle.

Based on the above, and the degradation demonstration both for Longview as well as the appropriate fleet data, CF cannot and should not be fully removed from the degradation rate. An appropriate rate has been determined and presented which accurately reflects the unit operation into the future as it ages, and is supported by the included fleet performance data.

Startup/Shutdown "Bin 0" Influences and Factors

Startup/Shutdown Operations (SUSD) on the Longview unit make up less than 1% of the total operating hours in the 2016 – 2020 Q2 sample data set. The Bin 0 calculations in regards to setting an appropriate Standard of Performance are unique for two primary reasons: the Longview unit doesn't operate in this region but only form startups and shutdowns, and; that CO_2 Rate is based on lbs/MWHN (lbs CO_2 on a net generation rate), and for most of the Bin 0 operations, no Net power is being generated. Add on the fact that while the emissions rates are much higher than in Bins 1-5, the time spent in Bin 0 is much lower, thereby resulting in a very small fraction of emissions being generated during SUSD operations.

Fundamentally, all factors create a situation where the unit operating time spent in Bin 0 is minimized as no revenue is being generated during operations, only cost. Additionally, the unit has regimented control logic with set time durations, as well as other critical physical design limitations that force the unit to be either starting up or shutting down – there is no real steady state operation in Bin 0. The unit is moved to Bin 1 and above as fast as is operationally possible, limited only by design and/or operational challenges in safely ramping load and maintaining unit operational stability while moving out of Bin 0. Factors such as vibration, fuel feed, and other O&M aspects can cause a reduced ramp rate, but these are to be expected, and minimized by the Operations staff. Based on all these factors, the Bin 0 separate calculation is necessary and appropriate, overall emissions from this calculation encompass a very small part of overall unit emissions, and all economic and operational factors encourage the unit to move out of Bin 0 as quickly as is safely possible. Longview has provided the technical demonstration in support of the proposed Bin 0 Standard of Performance but remains interested and open to the integration of an alternative regulatory treatment of SUSD that would rely upon work practice standards linked to the operation and maintenance of HRI-related equipment and practices as an alternative to a numeric Bin 0 standard to govern units for the limited time during which they are in SUSD.

Effects of Fuel Characteristics on CO_2 Performance and Heat Rate

Fuel characteristics have substantial influence over heat rate and CO_2 performance and are fundamental to unit performance. Minor changes in a variety of characteristics can directly influence not only combustion performance, but also increased auxiliary loads based on additional pollution control equipment needs. Increased CO_2 emission rate and heat rate may be solely caused by the change, rather than a change in unit efficiency. Coal characteristics from a specific seam are relatively consistent although these characteristics do materially vary. Changing sources of fuel that are sourced even from the same seam may be significant enough to make a relevant difference in unit efficiency and thus compliance (example- other "modern US coal plant better net overall efficiency than Longview but do not due to the relative advantage of Longview's "High energy density Northern Appalachian" fuel over, say Powder River Basin Fuel). The result of these factors is that the complexities of how fuel is utilized in these units encompass significant multi-variables and the complex interactions do not lend themselves to formulaic conclusions. It is imperative that fuel be considered not only when setting the standards, but as a catalyst for review when the fuel source changes either voluntarily or forced. Due to significant instability in the current coal supply chain, coal-fired units cannot count on continuing to receive the same coal they may have burned during the sample period. Therefore, the ability to trigger a reassessment of the CO_2 Standard of Performance based on fuel change is critical to the economic health of all coal-fired units as in the even a current fuel supplier ceased operation, and no equivalent fuel could be obtained, units may be forced to shut down if the alternative fuels would not allow compliance with the in-effect Standard of Performance.

Operation and Maintenance Manual

Saturday, September 19, 2020 9:03 AM

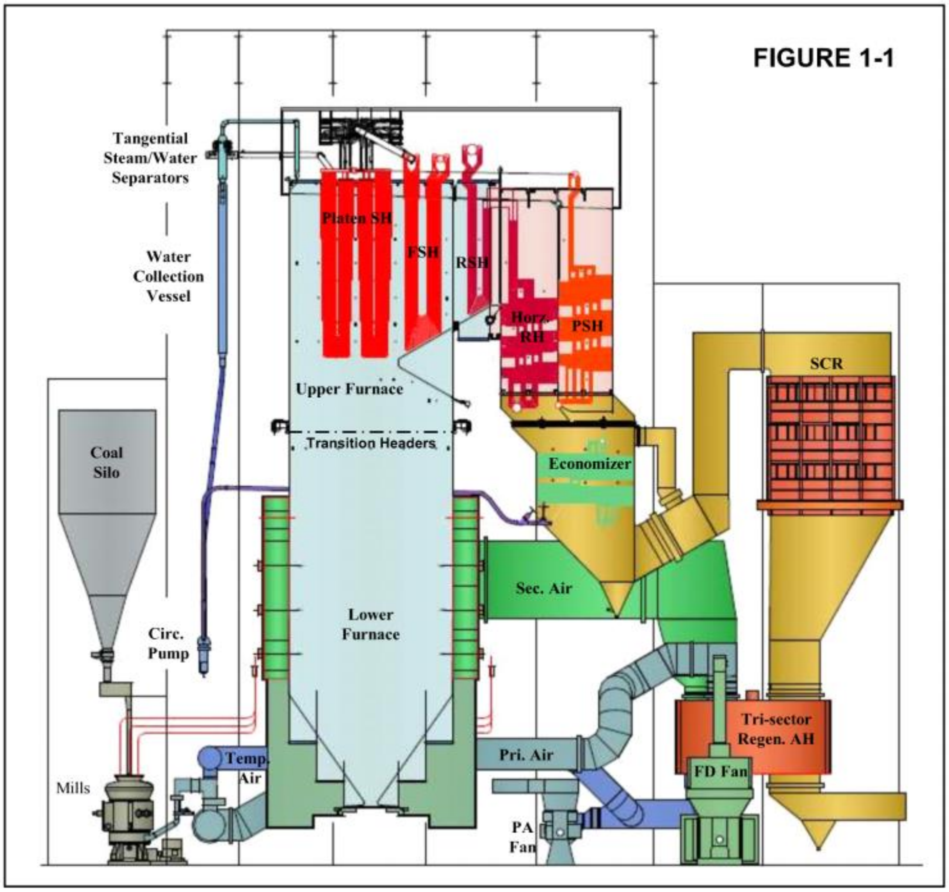
SECTION 1

DESCRIPTION

1.1 GENERAL

The Foster Wheeler-BENSON Vertical once-through, supercritical steam generating unit consists of a vertical tube water wall furnace, primary superheater, platen superheater, finishing superheater, single stage reheater, and economizer. The unit is illustrated in Figure 1-1. Final superheater steam temperature is controlled by spray water attemperators and fuel-feedwater flow control. Two (2) stages of interstage spray water attemperators, one (1) upstream of the superheater platen and one (1) downstream of the superheater platen are provided for final superheater steam temperature control. Reheat steam temperature is controlled by gas flow proportioning through the parallel pass heat recovery area (HRA). An emergency spray water attemperator is provided in the reheat inlet piping for transient operation.

FIGURE 1-1



The unit is designed to fire pulverized coal (PC) in a balanced draft furnace through Foster Wheeler Vortex Series/Split Flame (VS/SF) Low NOx burners. Each burner includes a natural gas fired ignitor with high energy spark ignition and flame detectors. Each of the six (6) MBF 23 Foster Wheeler coal pulverizers feeds six (6) burners. Axial flow type forced draft fans provide combustion secondary air to the burners and centrifugal type primary air fans provide primary air to the pulverizer-burner system. The furnace draft system is controlled by induced draft fans supplied by others. A bottom ash system is provided for the furnace ash hopper.

Included in each boiler outlet flue is a Selective Catalytic Reduction (SCR) System for NOx control. An aqueous ammonia system is provided with vaporizers for distribution of the vapor to an ammonia injection grid (AIG) upstream of each SCR. The system includes an aqueous ammonia unloading skid, two (2) storage tanks, a pumping skid, two (2) vaporizer-dilution air skids, dilution air heaters, and two (2) AIGs.

A tri-sector regenerative air heater is installed downstream of each SCR to preheat the primary and secondary air. A steam coil air heater (SCAH) is installed between each of the secondary air fans outlets and the regenerative air heater inlets for cold end corrosion protection. A collection tank and pump are included to return the SCAH and auxiliary steam drains to the deaerator.

The air quality control equipment is furnished by others.

A boiler start-up system is provided, which includes four (4) tangential entry steam separators, one (1) water collecting vessel, one (1) circulating pump, and steam and water piping and valves. The separated water is drained from the separators to the water collecting vessel from where it is pumped back to the economizer inlet to establish the minimum fluid mass flow for furnace protection and to recover heat. The separated steam is distributed from the separators to the superheaters for warming the downstream components. During initial firing excess water is drained from the water collecting vessel to the condensate system.

A boiler drains tank is provided to receive all the boiler drains for waste disposal.

A natural gas fired auxiliary package boiler is included to supply steam to the auxiliary steam system during start-up, from which steam is distributed to each SCAH, to the pulverizer inerting system, and to the main deaerator for pegging steam. The auxiliary boiler is equipped with a burner, igniter, instrumentation and controls, FD fan, boiler feed pump, deaerator, blowdown tank, and stack.

A boiler island elevator is provided.

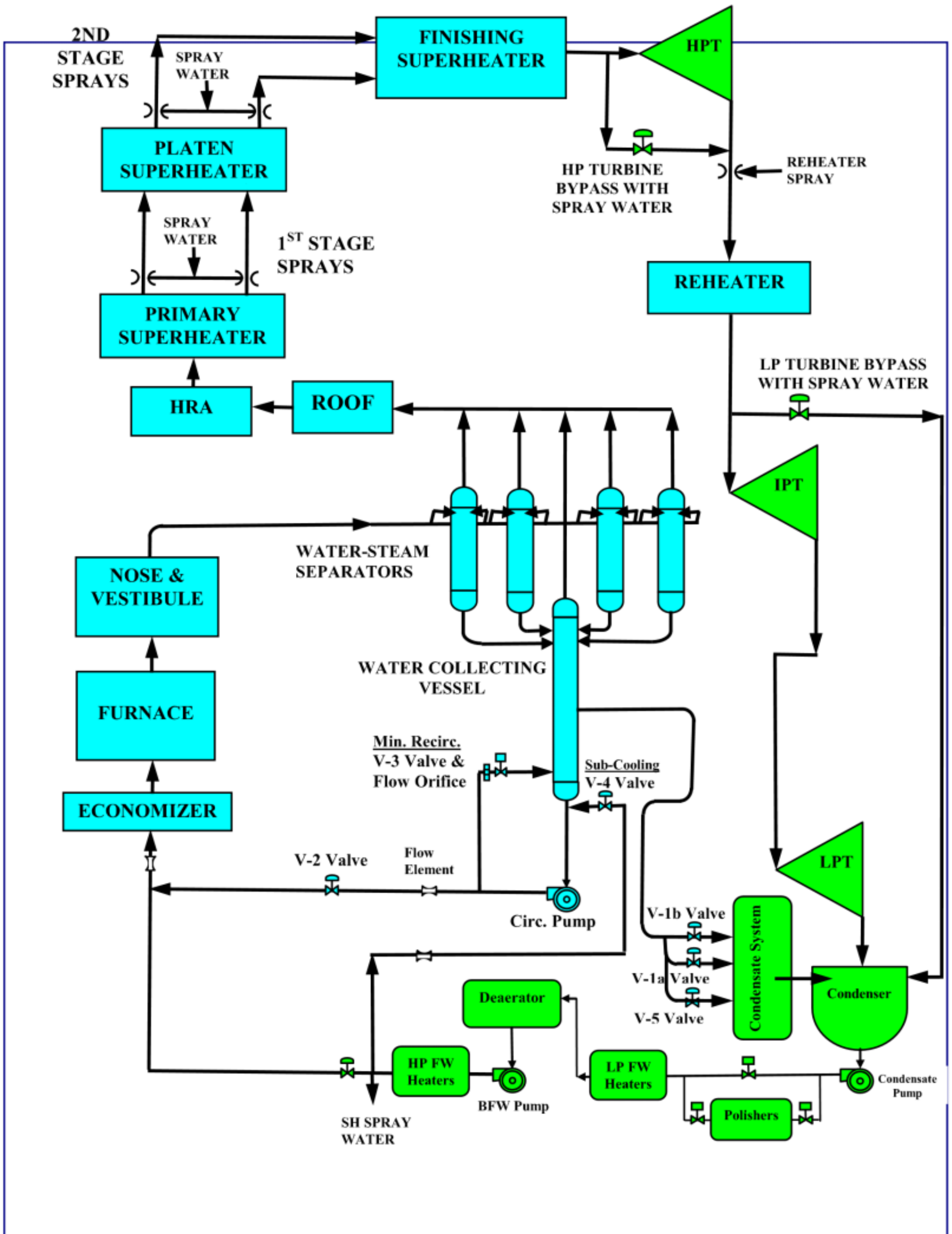
Table 1-1, Predicted Steam Generator Data, (located at the end of this Section 1) tabulates physical and operational data for this unit for several load conditions. Descriptions of the operating components of the steam generator are given below. Installation, operation and maintenance instructions for auxiliary equipment manufactured by others and supplied by Foster Wheeler are contained in subsequent parts of this manual.

The P&ID Legend and Drawing Index is provided in Table 1-2 at the end of this Section 1. The Process and Instrumentation Diagrams (P&ID's) are provided at the end of this Section 1 and are referred to, as necessary, in the following descriptions. In addition, the Instrument Index is provided at the end of this Section 1 to identify all items depicted on the P&IDs.

1.2 WATER AND STEAM FLOW

Figure 1-2 and Drawings 120231-60-6102 through -6107 show diagrammatically the flow paths of water and steam through the unit in the sequence outlined below:

FIGURE 1-2



1. Economizer - Feedwater is introduced into the unit through the economizer which is positioned at the bottom of the HRA below the parallel pass dampers. From the economizer the heated feedwater leaves each end of the outlet header and flows down externally to a common, unheated transfer pipe to the furnace inlet. From the common transfer pipe, a pair of pipes extend to each furnace sidewall where they branch again and extend to a total of four(4) distribution bottles positioned at approximately the quarter points along the furnace front and rear walls. Multiple feeder pipes extend from the distribution bottles to deliver water to the furnace wall panel lower headers.

2. Boiler - The furnace circuitry consists of a lower section with optimized, vertical rifled tubes that extend up to transition headers located at an elevation below the furnace nose. From the transition headers, vertical smooth bore tubes extend up the furnace walls to the furnace roof, and also form the furnace exit screen and part of the vestibule side walls. The tube panels that form the furnace enclosure are of Monowall™ type construction. Riser pipes extend from the furnace enclosure upper headers to a collection manifold from which the flow is directed to the final steam generator zone that forms the furnace nose, vestibule floor and a portion of the vestibule sidewalls. Steam from this zone flows to four (4) in-line steam/water separators connected in parallel, which are part of the start-up system as described below.

3. Superheaters - From the in-line steam/water separators the fluid passes through the superheater circuitry which includes the furnace roof, the heat recovery area (HRA) enclosure and part of the vestibule sidewalls, the primary superheater located in the outboard pass of the parallel pass HRA, the furnace platen superheaters, and the pendant finishing superheater at the furnace exit. For the HRA enclosure, flow from the furnace roof is delivered to the HRA partition upper header and is passed down in parallel through the HRA rear wall, sidewalls, front wall, vestibule sidewalls, and HRA partition wall before it is directed to the primary superheater. Spray water attemperators are positioned upstream of the furnace platen superheater, and the pendant finishing superheaters for initial final main steam temperature control which is coordinated with the feedwater and firing rate controls.

4. Reheater - Reheat steam is first heated in the horizontal surface located in the inboard pass of the HRA. The reheater tubes then extend through connecting tubes into the vestibule area pendant surface to achieve the final reheat steam temperature. Reheat steam temperature is controlled by multi-louver dampers, which proportion gas flow through the parallel pass HRA. A spray water attemperator is provided in the inlet piping for transient conditions.

5. HP/LP Turbine Bypass - The plant design includes high pressure (HP) and low pressure (LP) turbine bypass systems (supplied by others) to facilitate start-up and other conditions.

6. Steam Generator Start-Up System - Before fuel can be fired in a once-through boiler, a minimum fluid mass flow rate must be established within the boiler tubes that form the furnace enclosure to protect the tubes from overheating. This minimum flow is provided by the feedwater pump and a recirculation pump that returns the heated water back to the economizer inlet in a closed loop. During this start-up phase the

boiler is controlled similar to a drum type boiler by having the startup system downstream of the evaporator to separate liquid and vapor phases as firing rate increases. Water is drained from the water collecting vessel and recirculated back to the economizer inlet. To ensure that sub-cooled water enters the pump, a small amount of cold feedwater is piped to the pump inlet line.

1.3 AIR AND GAS FLOW

Drawings 120231-60-6108 through -6113 show diagrammatically the air and gas flow paths through the unit. Secondary air is delivered by forced draft fans through steam coil air heaters to the secondary air-section of the trisector regenerative air heaters. Primary air is delivered by primary air fans to the primary air section of the trisector regenerative air heaters. Heating elements, which rotate continuously through the gas and air sections of the air heaters, absorb heat from the hot flue gas in the gas section, and rotate to the primary and secondary air sections to heat these incoming air steams. The heated secondary air then flows through ducts into both the burner windbox and furnace overfire air ports located on the furnace front and rear walls. The heated primary air flows through ducts to the pulverizers, where it evaporates surface moisture from the coal for grinding and is then delivered to the burners. The furnace windbox is compartmentalized and dampers control the secondary airflow to six (6) burners in each compartment row. There are three (3) rows of burner compartments on each wall, each supplied by one (1) pulverizer. The burners in each pulverizer group are the burners in one row on one side of the furnace. The secondary air flows through the burner air registers and overfire air ports on the furnace front and rear walls and into the furnace. There the secondary air mixes with the primary air-pulverized coal fuel mixture for combustion.

The hot gas produced by the burning of fuel flows upward giving up heat to the furnace waterwalls and furnace superheater platens. The gas then exits the furnace and flows across the finishing superheater above the nose, the finishing reheater in the vestibule, and through the furnace rear waterwall screen. The gas then flows down through the HRA in two (2) parallel gas paths, which divide the HRA in the front to rear direction. The forward gas path contains the inlet, horizontal sections of the reheater and the rearward gas path contains the primary superheater. The parallel down-pass gas flow split is proportioned by control dampers located at the bottom of each pass. The flue gas then flows through the economizer, the exit flue, and is drawn through the Selective Catalytic Reduction (SCR) System, through the dilution air induct heat exchanger and then the flue gas section of the tri-sector regenerative air heater. The gas then flows through the Air Quality Control System, through the ID Fan, and then to a stack from which it enters the atmosphere.

The pulverizer primary air system is described in Section 1.7.

1.4 STEAM GENERATING COMPONENTS

1.4.1 ECONOMIZER

A bare tube economizer is arranged at the bottom of the HRA downstream of the parallel pass control dampers. The economizer cools the flue gas before it exits the unit. Incoming feedwater enters the lower inlet header, flows upward through the economizer tubes in counter flow to the flue gas, leaves through the upper outlet header and is piped to the lower furnace inlet bottles through transfer pipes.

1.4.2 FURNACE AND VESTIBULE

The furnace is approximately 75' wide, 52' deep and 196' high and consists of front, rear and side waterwalls of welded tube wall construction.

The bottom of the furnace is arranged with a dry ash hopper, formed by the front and rear walls with the center space open for discharge of ash.

The upper rear wall of the furnace has a "nose" section to distribute the gas flow to the heat transfer surfaces located in the upper furnace and vestibule areas. Some of the furnace rear wall tubes become rear screen tubes, providing water cooled support for the rear wall by carrying these loads to the rear screen outlet header, and to the top support steel. A portion of the rear wall tubes near the screen tubes are aligned with the screen rows to form the gas lanes and the remaining tubes closest to the sidewalls are bent to form part of the vestibule sidewall panels.

The welded fin tube furnace panels of the lower furnace surrounding the high heat zone, in the front, rear and side walls incorporate optimized rifled tubing. This tubing starts at the hopper throat elevation and ends near the transition headers elevation.

The lower furnace contains thirty-six (36) burners, three (3) rows of six (6) burners per row on the front and rear walls. Above the top row of burners are sixteen (16) overfire air ports, eight (8) each on the front and rear walls. One (1) lower overfire air port is located near each sidewall on the front and rear walls at the middle burner elevation, total of four (4) ports.

The upper furnace tubes in the second zone above the transition headers elevation consists of smooth bore tubing.

The third and final boiler zone forming the nose and vestibule floor, and part of the vestibule sidewall panels consist of smooth bore tubing.

1.4.3 ROOF, VESTIBULE, and HEAT RECOVERY AREA

The outlet piping from the in-line steam/water separators supplies the furnace roof inlet header, which feeds the roof tubes. The roof tubes exit to the upper partition wall inlet header, which supplies the HRA roof and rear wall, and the HRA partition screen and partition wall. Feeders connect from the partition wall inlet header to the upper HRA inlet headers, which supply the enclosure panels for the HRA sidewalls, HRA screen tubes and front wall, and part of the vestibule sidewalls. The partition wall lower outlet header collects the flow from the HRA lower outlet headers and supplies the primary superheater.

1.4.4 PRIMARY SUPERHEATER

The horizontal primary superheater is located in the rear pass of the HRA. Steam from the lower inlet header flows up through the sections of horizontal elements arranged in 3 banks across the width of the unit.

Steam from the primary superheater is collected in the upper outlet header. From each end of the outlet header, the steam flows through the first stage spray attemperators to each end of the platen superheater inlet header.

1.4.5 FURNACE SUPERHEATER PLATENS

The platen superheater consists of evenly spaced sections across the width of the upper furnace. Each platen has two inlet and two outlet legs per section.

Steam enters each end of the platen superheater inlet header from the spray piping connected to the primary superheater outlet header, flows through inlet bottles and then into the tube elements. The steam flows down through the inlet legs, up the outlet legs, and into the outlet bottles. Risers from the outlet bottles connect to the collection headers and to the transfer piping which contains the second stage attemperators. After the attemperators the steam flows to the finishing superheater inlet header.

1.4.6 FINISHING SUPERHEATER

The finishing superheater located above the furnace nose, consists of evenly spaced sections across the width of the unit.

Steam enters each end of the finishing superheater inlet header, and flows through the superheater elements to the outlet header. The steam then leaves through each end of the outlet header and flows to the high pressure turbine.

1.5 REHEATER

There are two (2) reheater sections in the steam generator. The first section is horizontal surface located completely in the front pass of the HRA. The second section consists of vertical tubes in the HRA connecting to pendant sections in the vestibule. The parallel pass control dampers proportion flue gas between the SH and RH passes to control reheater outlet temperature. An emergency spray attemperation system is installed in the cold reheat piping for transient load RH steam temperature control.

Steam from the high pressure turbine cold reheat pipe enters the reheater through the inlet header, flows upward through the horizontal elements, flows through the pendant sections, leaves through the outlet header, and exits the steam generator through the hot reheat pipe to supply steam to the intermediate pressure turbine.

1.6 START-UP SYSTEM

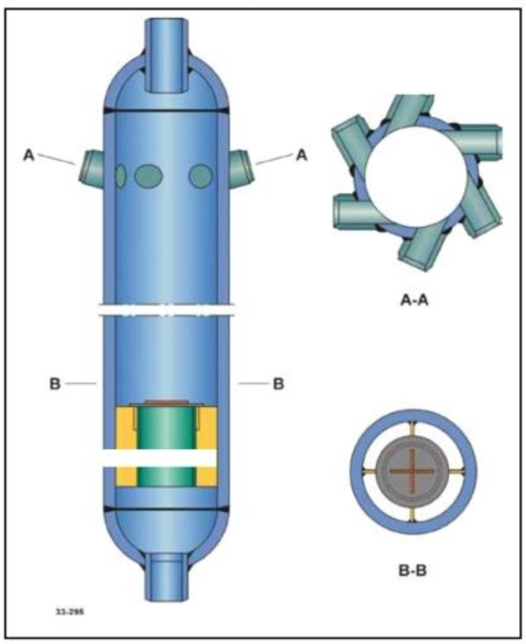
The design includes four (4) tangential type separators with a single water collecting vessel. During initial firing, the inventory of water within the boiler expands. Excess water is drained from the water collecting vessel to the condensate system to maintain an acceptable water level within the water collecting vessel. As load is increased, the amount of collected water diminishes so that at the BENSON load only superheated steam is passing through the separators. At this point the transition to once-through control is made with feedwater flow and firing rate coordinated to achieve the target final main steam temperature.

1.6.1 START-UP SYSTEM COMPONENTS (illustrated in Drawing 120231-60-6104)

1.6.1.1 Boiler outlet transfer pipes connecting to the tangential separator inlet feeder pipes

1.6.1.2 Four (4) steam separators (See Figure 1-3), each with six (6) tangential inlets shown by Section A-A, a vortex inhibitor shown by Section B-B, one (1) top steam outlet connection, and one (1) bottom water outlet connection.

FIGURE 1-3 Tangential Separator

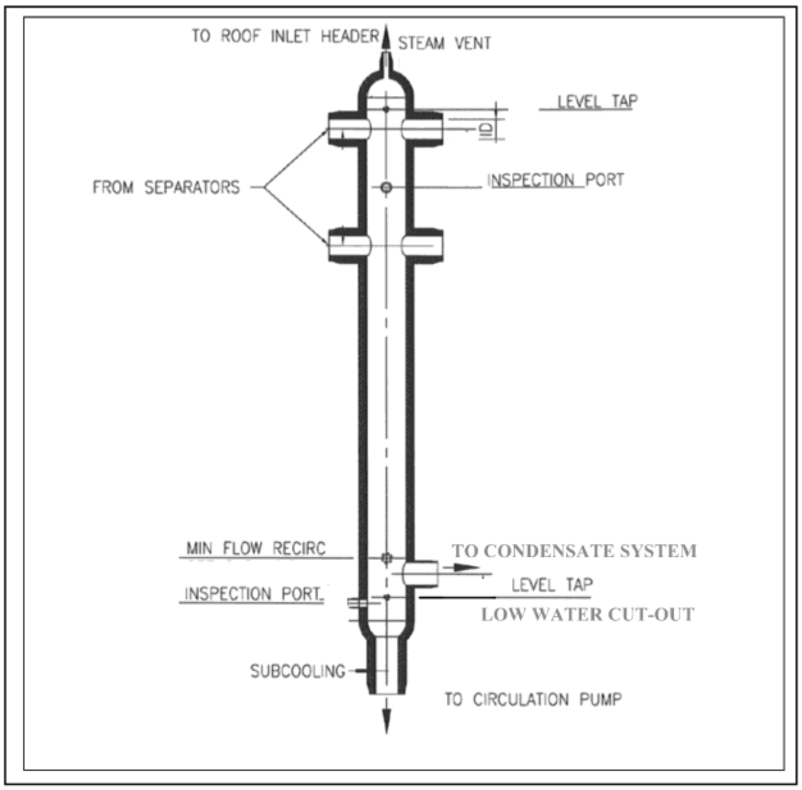


1.6.1.3 Separator outlet steam piping for return of steam to the furnace roof inlet header

1.6.1.4 Separator outlet water piping connecting all four (4) separators to a common water collecting vessel.

1.6.1.5 One (1) water collection vessel (See Figure 1-4) with four (4) inlet connections, one (1) pump minimum flow recirculation connection, one (1) overflow connection to the condensate system, and one (1) bottom outlet connection to circulation pump.

FIGURE 1-4
Typical Water Collecting Vessel



1.6.1.6 Piping connecting the water collecting vessel to the circulation pump inlet and the circulation pump discharge to the economizer inlet mixing tee with circulation control valve (V-2), motor operated block valve, check valve, and flow measuring nozzle

1.6.1.7 One (1) circulation pump

1.6.1.8 Circulation pump minimum flow recirculation line, returning discharge flow to the water collecting vessel, including orifice and motor operated block valve (V-3).

1.6.1.9 Water collecting vessel over-flow connection for returning water to the condensate system with control valves (V-1a and V-1b) and corresponding motor operated block valves.

1.6.1.10 High pressure superheater attemperator spray water connection to the water collecting vessel discharge pipe to control a minimum sub-cooled temperature margin to the circulation pump with control valve (V-4), motor operated block valve, check valve, and flow nozzle.

1.6.1.11 Warming lines, including orifices and isolation valves, from the economizer outlet to the start-up system, and to the condenser through the V-5 valve.

1.6.2 START-UP SYSTEM FUNCTIONS

In summary, the start-up system performs the functions below:

1.6.2.1 Furnace Cooling - The furnace is protected from overheating at less than minimum load by circulating the minimum fluid mass flow through the circuitry. The combined flows of the circulated flow from the start-up system and boiler feedwater are coordinated to control the minimum fluid mass flow through the furnace.

1.6.2.2 Separates Steam - The separators provide steam for warming the downstream boiler components, piping, and turbine equipment.

1.6.2.3 Separates Water - The separators and water collection vessel provide warmed water for circulating back to the boiler-economizer for heat recovery as limited by economizer steaming and the minimum sub-cooled margin to saturation temperature at the furnace inlet.

1.6.2.4 Superheater and Turbine - The separators provide dry steam to the superheaters, piping and turbine. The water collecting vessel provides surge capacity for water swell created during a start-up or after burner light-off during a hot restart.

1.6.2.5 Water Cleanup – Provides a water path through the feedwater system, economizer, and water walls to the condensate system and to the condensate polishers for cleanup.

1.6.3 CIRCULATING PUMP

The following lists special features for the circulation pump and motor:

1.6.3.1 The circulation pump is a "wet stator, motor-under" type designed for high pressure boiler service, which is suspended from its inlet and outlet piping systems.

1.6.3.2 The suction line descends vertically downward from the water collecting vessel bottom outlet to the pump inlet nozzle.

1.6.3.3 The pump is welded to its suction and discharge lines, but the motor housing has a flanged connection to the pump casing to allow withdrawal of the rotating assembly for inspection, repair, and when flushing debris from the system or chemical cleaning.

1.6.3.4 The motor is mounted below the pump on a common shaft in a seal-less motor and pump system.

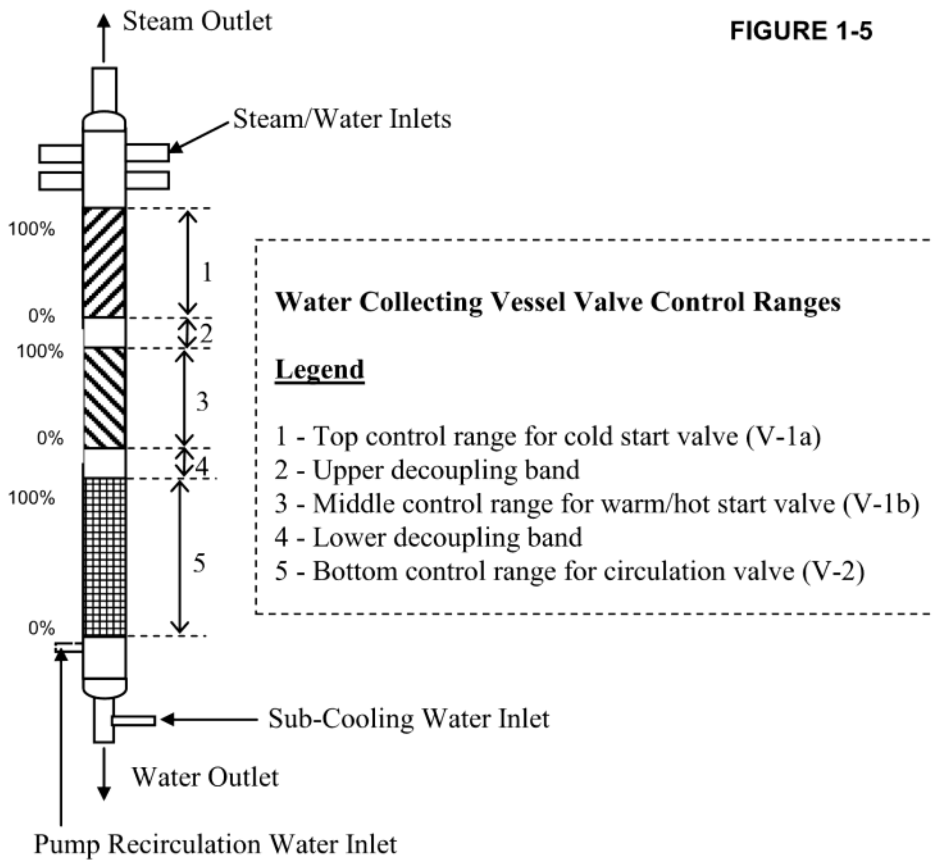
1.6.3.5 The motor is kept cool via an external heat exchanger.

1.6.3.6 The motor windings are coated with a high-dielectric strength polymer to withstand water exposure.

1.6.4 START-UP SYSTEM VALVES

The start-up system valves (V-1a, V-1b, and V-2) are assigned to control water level bands in the water collection vessel as depicted in Figures 1-5 and 1-2.

FIGURE 1-5



1.6.4.1 V-2 valve controls the lowest band (5) for circulation to the economizer inlet.

1.6.4.2 V-1a valve controls the upper band (1) for dumping excess water to the condensate system during a cold start.

1.6.4.3 V-1b valve controls the middle band (3) for dumping excess water to the condensate system during a warm/hot start.

1.6.4.4 The V-3 valve controls recirculation to the water collection vessel for pump minimum flow protection.

1.6.4.5 After the circulating water temperature exceeds the feedwater temperature by 20 ^{o}F or more, sub-cooling valve V-4 is placed into service to control a minimum sub-cooling temperature of 20 ^{o}F to the pump to prevent suction line flashing and cavitation.

1.6.4.6 Decoupling bands (2 and 4) are required to prevent overlapping level control interferences.

1.7 PULVERIZED COAL SYSTEM AND PULVERIZER INERTING SYSTEM

The pulverized coal system consists of the following principal components. This system is shown schematically in Drawings 120231-60-6113 through 6125. See Section 4 for more details:

Six (6) Foster Wheeler MBF 23 Pulverizers

Six (6) Gravimetric Feeders, one for each pulverizer

During operation, raw solid fuel is fed to the top of each pulverizer by a gravimetric feeder. The fuel is deposited in the pulverizer's` grinding section where it is ground and then transported by an up-flow of primary air to the coal classifier section of the pulverizer. The classifier section allows suitably sized fuel particles to be carried by the primary air through the coal-air conduits to the coal burners. Larger fuel particles rejected from the classifiers flow back to the grinding section for further pulverizing.

The primary air, used to carry the fuel through the pulverizer to the burners, is supplied by two (2) primary air fans, which force air through the primary air section of the tri-sector regenerative air heaters. Desired pulverizer outlet fuel-air temperature is achieved by tempering the hot primary air with tempering air from the primary air fan, which bypasses the air heater. Dampers at each pulverizer regulate the flow of tempering air based on the pulverizer outlet set point temperature.

Isolating portions of the pulverizer from the fuel particles is accomplished by seal air obtained from the cold primary air ducts.

Each pulverizer is equipped with an automatic/manual steam inerting system. The steam, controlled by the inerting systems, enters the pulverizers through a sparger in each of the primary air inlet ducts near the pulverizers. These systems are used to inert the pulverizers to prevent or extinguish fires.

A logic system is used to control the inerting system for automatic operation during pulverizer start-up, normal shutdown, emergency trip and coal grindout. The inerting system can also be operated in the manual mode as necessary.

1.8 BURNER AND OVERFIRE AIR SYSTEM

There are three (3) rows of six (6) burners on both the front and rear walls for a total of thirty-six (36) burners. Each pulverizer supplies coal to six (6) burners on one (1) horizontal row on one (1) wall. The burners are Foster Wheeler Vortex Series/Split Flame Low NOx burners. The burner system is designed with individual damper control for the secondary air.

Tertiary air is supplied to all the burners. This air flows through the inner barrel of each burner for purging this area to prevent the buildup of coal or ash. Two (2) 100% tertiary air fans provide the airflow for this system.

The overfire air system consists of sixteen (16) air ports located above the top row of burners, eight (8) on the front wall and eight (8) on the rear wall. In addition, one (1) lower overfire air port is located near each sidewall at the center burner row elevation, for a total of four (4) lower overfire air ports. Each wall has a windbox that provides air to the overfire air ports on that wall. Two control dampers, one on each end of the windbox, regulate the flow to each windbox. In this manner, the overfire air flow to the front and rear wall are separately controlled for NOx control.

The burner secondary air, tertiary air and overfire air systems are shown schematically in Drawings 120231-60-6111 and -6112. See Section 5 for a detailed discussion of these systems.

1.9 STEAM TEMPERATURE REGULATION

Steam temperature from the superheater is controlled by spray water attemperation and by coordinating fuel and feedwater flow rates. Water spray attemperators are located at the inlets to the platen superheater and to the finishing superheater for final steam temperature control. Steam temperature from the reheater is controlled by the parallel pass gas control dampers, which proportion flue gas between the RH and SH passes. For transient load or emergency control of the reheater steam temperature, a water spray desuperheater is provided in the cold reheat pipe, which is routed from the high pressure steam turbine to the reheater inlet header.

Thermal liners are provided within attemperators assemblies at the spray points to protect the piping from thermal shock. The steam is cooled as the spray water is mixed with the steam and evaporated in the liner zones.

The superheater first and second stage stations incorporate two (2) water nozzles each. The reheater spray station has one (1) water spray nozzle.

The second stage attemperators upstream of the finishing superheater provides inital steam temperature control. The first stage attemperators upstream of the platen superheater provides support adjustment to keep the second stage attemperator control valves within control range. The first stage attemperator control valves are kept in control range by trimming the evaporator outlet enthalpy through changing the feedwater flow.

1.10 SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM

An SCR system is provided to further reduce NOx in the flue gas. Selective Catalytic Reduction is the process in which NOx in the flue gas, when reacted with ammonia in the presence of a catalyst, is converted to nitrogen and water vapor. Ammonia is injected into the flue gas stream upstream of each of the two (2) reactors that contains the catalyst. An aqueous ammonia unloading station, storage tanks, pumping skid, vaporization and dilution air skids with metering, and ammonia injection grid are included. There are two (2) initial rows of catalyst and provision for a third row. Sonic horns are provided for removing ash from the catalyst layers. See Section 6 for details of the SCR system. This system is shown schematically in Drawings 120231-60-6126 through 6130.

1.11 AUXILIARY EQUIPMENT

The equipment listed below has been supplied by Foster Wheeler for use in operation of the steam generator. The manufacturer's instructions for the installation, operation and maintenance of this equipment are contained in subsequent parts of this manual which are identified by the tabs (**Part 2, Part 3, etc.**).

NOTE

Refer to the Master Index at the beginning of each volume for physical location of vendor's literature.

1.11.1 Circulation Pump

Furnished by Torishima Pump Manufacturing Co., Ltd.

1.11.2 Fuel Burner Accessories

Logic for the Burner Management System, including ignitors and accessories furnished by Forney Corporation

Thirty-six (36) High Energy Spark Ignitors (HESI), Gas Ignitors with High Energy Spark Igniters furnished by Forney Corporation

Thirty-six (36) UNIFLAME Flame Detectors with fiber optic probes for detecting ignitor flame furnished by Forney Corporation

Thirty-six (36) UNIFLAME Flame Detectors for detecting main flame furnished by Forney Corporation

1.11.3 Safety Valves

Safety Valves and Electromatic Relief Valve are furnished by Dresser Industries (Consolidated) as follows:

Loc.	NO. REQ'D	Size (in.)	Mfrs. Type No.	Relief. Press. (psig)	Capacity Each (lb/hr)
Roof Inlet	NOTE 1	3x8	1753WD	4710	922,501
FSH Outlet	NOTE 2	2.5x6	1733WF	4179	401,596
FSH Outlet: ERV	NOTE 3	2.5x4	3547W(V)	4045	365,744
ERV Isolation Valve	Four (4)	2.5x2.5	2.5 IBV-1.77-4500		
RHO	NOTE 4	6x10	1786WF-HP	930	464,588
RHO	NOTE 4	6x10	1786WF-HP	930	464,588
RHI	NOTE 5	6x10	1706RRWD-HP	975	827,440
RHI	NOTE 5	6x10	1706RRWD-HP	985	835,804
RHI	NOTE 5	6x10	1706RRWD-HP	995	844,168
RHI	NOTE 5	6x10	1706RRWD-HP	1004	851,696

NOTES:

1. Four (4) - one (1) in each of the four (4) steam/water separator steam outlet pipes with Tag Numbers 10HAD41-BR191, 10HAD42-BR191, 10HAD43-BR191, and 10HAD44-BR191
2. Two (2) - one (1) in each MS pipe branch connected to each end of FSH Outlet header with Tag Numbers 10HAH61-AA191 and 10HAH62-AA191
3. Four (4) - two (2) in each MS pipe branch connected to each end of FSH Outlet header with Tag Numbers 10HAH81-AA051, 10HAH82-AA051, 10HAH83-AA051, and 10HAH84-AA051
4. Maximum relieving capacity for RHO safety valves with Tag Numbers 10HAJ61-AA191 and 10HAJ62-AA191
5. Maximum relieving capacity for RHI safety valves with Tag Numbers 10HAJ51-AA191, 10HAJ52-AA191, 10HAJ53-AA191, and 10HAJ54-AA191

1.11.4 Valves

Spray Block and Control Valves and Accessories (SPX/Copes Vulcan)

First Stage Superheater:
Two (2) 4”, Model SD-700-160L RA, Spray Block Valves
Two (2) 4”, Model SD-AUMA SAR 10.1, High Flow Spray Block Valves
Two (2) 4”, Model SD-1000-320RA, High Flow Spray Control Valves

Second Stage Superheater:
Two (2) 4", Model SD-700-160L RA, Spray Block Valves
Two (2) 4", Model SD-AUMA SAR 10.1, High Flow Spray Block Valves
Two (2) 4", Model SD-700-160 RA, High Flow Spray Control Valves

Reheater:
One (1) 6", Model SD-700-160RA, Spray Block Valve
One (1) 6", Model SD-700-160 RA, Spray Control Valve

Feedwater Stop and Check Valves (Tyco Valves)

One (1) 20", Dewrance Figure # F95EZ500NFD, Feedwater Check Valve
One (1) 20", Figure # W431XPP, Feedwater Stop Valve

Main Steam Stop Valves (Tyco Valves)

Two (2) 24", Figure # AW531DPP

1.11.5 Fans

Two (2) Axial Flow Forced Draft Fans furnished by Flakt Woods Company driven by Single Speed Electric Motors furnished by Hyundai Heavy Industries

Two (2) Centrifugal Primary Air Fans with Variable Inlet Vane control furnished by Flakt Woods Company driven by Single Speed Electric Motor Drives furnished by Hyundai Heavy Industries

Two (2) Tertiary Air Fans furnished by Northern Blower driven by Single Speed Toshiba Electric Motors

1.11.6 Air Preheaters

Two (2) Trisector Air Heaters furnished by Alstom

Two (2) secondary air Steam Coil Air Heaters furnished by Aerofin

One (1) Steam Coil Air Heater Condensate Drain Tank furnished by RV Industries

One (1) Steam Coil Air Heater Grundfos Condensate Drain Pump furnished by Pumping Equipment Company to return the condensate to the Deaerator

1.11.7 Pulverizer Accessories

Thirty-six (36) Burner Shut-off Valves and Thirty-six (36) Burner Barrier Valves furnished by Stock Equipment Company

Six (6) Bevel Planetary Drive Speed Reducers furnished by Formosa Heavy Industries

Six (6) Classifier Vane Actuators furnished by Technical Components

Six (6) Gravimetric Coal Feeder Systems furnished by Stock Equipment Company

Six (6) Roller Seal Air Filters furnished by Solberg

1.11.8 Motors

Six (6) Pulverizer Motors furnished by Hyundai Heavy Industries

1.11.9 Sootblowers

Sootblowers and Accessories furnished by Diamond Power International, Inc.

1.11.10 Dampers and Actuators

The following Dampers furnished by Damper Design:

One (1) Reheat and One (1) SH Pass Dampers with ABB/TZID Actuators
Two (2) Economizer Bypass Control Dampers with ABB/TZID Actuators
Two (2) Air Heater Flue Gas Inlet Dampers with Limitorque Actuators
One (1) Cold Primary Air Crossover Damper with Limitorque Actuators
One (1) Secondary Air Crossover Damper with Limitorque Actuators
Two (2) Air Heater Primary Air Outlet Dampers with Limitorque Actuators
Two (2) Air Heater Sec. Air Outlet Dampers with Limitorque Actuators
Six (6) Hot Primary Air Dampers with ABB/TZID Actuators
Six (6) Tempering Air Dampers with ABB/TZID Actuators
Six (6) Total Primary Air Capacity Dampers with ABB/TZID Actuators
Six (6) Primary Air Shutoff (PASO) Dampers with Limitorque Actuators
Four (4) Overfire Air Port Dampers with ABB/TZID Actuators
Twelve (12) Windbox Inlet Control Dampers with ABB/TZID Actuators

1.11.11 SCR

Two (2) SCR Reactors furnished by FWNAC

SCR Catalyst furnished by Haldor Topsoe, Inc.

Ammonia Injection Grids (AIG) and static mixers furnished by Sulzer

Butterfly Valves for AIG furnished by Advanced Valve Design

Sonic Horns for cleaning catalyst furnished by GE Energy

Ammonia Unloading and Storage, Pump Forwarding, Vaporizers and Dilution Air Equipment, and Distribution Skids furnished by Integrated Flow Solutions (IFS)

Two (2) Dilution Air Induct Air Heaters furnished by Greens Power Equipment

1.11.12 Miscellaneous

Various Seal Air Valves furnished by Solberg Manufacturing

Oxygen Analyzers furnished by Yokogawa Corporation

NOx and CO Analyzers furnished by SICK Maihak, Inc.

Thermocouples furnished by Temp-Pro, Inc.

Bottom Ash System furnished by United Conveyor Corporation

1.12 AUXILIARY BOILER

The auxiliary boiler has been supplied by ISGEC John Thompson (Noida, Uttar Pradesh, India) for use in plant start-up. The manufacturer's instructions for the installation, operation and maintenance of this equipment are contained in subsequent parts of this manual which are identified by the tabs (**Part 2, Part 3, etc.**).

NOTE

Refer to the Master Index at the beginning of each volume for physical location of vendor's literature.

TABLE 1-1 (SHEET 1 OF 2)
PREDICTED STEAM GENERATOR DATA

Fuel: Performance (Sewickley)					
Load		40%	75%	100% RL	VWO (5 mills)
Steam Flow	klb/hr	2010.9	3770.4	4876.4	5027.2
SH Outlet Pressure	psia	1667	3026	3735	3840
SH Outlet Temperature	F	1056	1056	1056	1056
Feedwater Inlet Temperature	F	482	543	569	571
RH Steam Flow	klb/hr	1754.6	3165.0	4012.2	4125.9
RH Outlet Pressure	psia	355	635	802	824
RH Outlet Temperature	F	1025	1052	1052	1052
RH Inlet Pressure	psia	367	657	830	853
RH Inlet Temperature	F	656	643	643	639
Ambient Temperature	F	63	63	63	63
Air Temperature Entering Unit	F	111	107	73	75
Air Temperature Leaving AH (Secondary)	F	480	514	515	518
Air Entering Air Heater	klb/hr	2302.5	3716.7	4820.1	4971.1
Gas Temperature Entering AH	F	593	631	666	668
Gas Temperature Leaving AH (diluted)	F	252	262	269	271
Gas Temperature Leaving AH (undiluted)	F	266	272	280	281
Wet Gas Entering AH	klb/hr	2989.72	4789.95	5990.6	6156.5
Wet Gas Leaving AH	klb/hr	3288.7	5101.3	6350.0	6526.0
Excess Air	%	30	20	20	20
Fuel Fired	klb/hr	251.1	433	542	557.3
Efficiency (HHV)	%	89.96	90.15	89.07	89.10

Elevation: 1120 ft above sea level

TABLE 1-1 (SHEET 2 OF 2)
STEAM GENERATOR DATA

	PERFORMANCE COAL Eastern Bit. (Sewickley)
ULTIMATE ANALYSIS (% by wgt as rec.)	
Carbon	62.50
Hydrogen	4.40
Oxygen	6.16
Nitrogen	1.40
Sulfur	2.50
Ash	18.50
Moisture	4.50
Chlorine	0.04
Total	100.00
HHV, BTU/Lb as fired	11,000
Grindability (Hardgrove)	55
PROXIMATE ANALYSIS (% by wgt as rec.)	
Fixed Carbon	45.00
Volatile Matter	32.00
Ash	18.50
Moisture	4.50
MINERAL ANALYSIS OF ASH	
Fe_2O_3	14.90
Na_2O	0.49
K_2O	2.23
CaO	2.45
MgO	1.05
SiO_2	46.63
Al_2O_3	24.33
TiO_2	1.07
SO_3	2.63
P_2O_5	0.27
Strontium Oxide	
MnO_2	
BaO	
Undetermined	3.95
Total	100.00
FUSION TEMPERATURE OF ASH	
Initial Deformation (Red./Ox.)	2294/2538
Softening (H=W) (Red./Ox.)	2390/2572
Softening (H=1/2 W) (Red./Ox.)	2382/2597
Fluid (Red./Ox.)	2496/2627

Table 1-2 LIST OF DRAWINGS

Drawing Number	Description
120231-25-0020	General Arrangement Cross Section
120231-60-6101	Symbols, Legend and Drawing Index
120231-60-6102	Feedwater and Economizer
120231-60-6103	Evaporator (Boiler)
120231-60-6104	Separators
120231-60-6105	Primary Superheater
120231-60-6106	Platen and Finishing Superheaters
120231-60-6107	Reheater
120231-60-6108	Furnace
120231-60-6109	SCR and Flue Gas
120231-60-6110	Secondary Air and Gas Flow
120231-60-6111	Secondary Air and Burners
120231-60-6112	Tertiary Air and Burners
120231-60-6113	Primary Air
120231-60-6114	Pulverizer A
120231-60-6115	Pulverizer A Lube Oil and Steam Inerting
120231-60-6116	Pulverizer B
120231-60-6117	Pulverizer B Lube Oil and Steam Inerting
120231-60-6118	Pulverizer C
120231-60-6119	Pulverizer C Lube Oil and Steam Inerting
120231-60-6120	Pulverizer D
120231-60-6121	Pulverizer D Lube Oil and Steam Inerting
120231-60-6122	Pulverizer E
120231-60-6123	Pulverizer E Lube Oil and Steam Inerting
120231-60-6124	Pulverizer F
120231-60-6125	Pulverizer F Lube Oil and Steam Inerting
120231-60-6126	SCR A Sonic Horn System
120231-60-6127	SCR B Sonic Horn System
120231-60-6128	Aqueous Ammonia Storage & Unloading Facility
120231-60-6129	SCR A Aqueous Ammonia Injection
120231-60-6130	SCR B Aqueous Ammonia Injection
120231-60-6131	Sootblowers
120231-60-6132	Air Heater Sootblowers
120231-60-6133	Igniter Gas Header
120231-60-6134	Igniters – Front Wall
120231-60-6135	Igniters – Rear Wall
120231-60-6150	Tripper Floor Drains
120231-60-6151	Boiler Drain System
120231-60-6152	Auxiliary Steam System
120231-60-6153	Steam Coil Air Heaters (SCAH)
120231-60-6154	SCAH Condensate Recovery
120231-60-6155	Service Water
120231-60-6156	Closed Cooling Water System
120231-60-6157	Closed Cooling Water System
120231-60-6158	Service Air System
120231-60-6159	Instrument Air System
120231-60-6160	Steam Generator Building Heating & Ventilating

Emergency Heat Rate Analysis

Thursday, October 8, 2020 7:50 AM

Longview Power Emergency Heat Rate Analysis Narrative

Overview

There are a significant number of scenarios where an unexpected equipment failure or condition monitoring finding may require a critical piece of equipment to be taken out of service that has significant impact to efficiency, ACE CO_2 compliance, and economic viability of the generating unit. To accommodate these scenarios, the idea of a Level 2 compliance standard was developed, which accounts for the failure scenarios and resulting efficiency losses listed below, as well as similar events. In the following document, several realistic scenarios which have occurred or may be reasonably expected to occur, have been presented and their anticipated effect on unit efficiency calculated. These scenarios are representative of a wide variety of failure mechanisms however they are not all-encompassing as there are many variations possible and it is not the intent of this demonstration to describe every failure scenario in detail.

Baseline Scenario – This is the baseline unit operation and used as a standard of comparison for the failure scenarios to estimate heat rate losses.

Scenario 1 – High Backpressure

The case of failure of Circulating water pump, portion of the cooling tower, or portion of the condenser would have minimal impact to the amount of net generation the unit could produce but each of these scenarios would have a 7 – 10% impact to efficiency due to the increased back pressure on turbine in condenser.

The case of a circulating water pump failure, Longview has O&M strategies in place consistent with the BSER to largely mitigate this risk. Part of this mitigation is proper operation and oversight, proper maintenance, advanced condition monitoring with items such as continuous vibration and temperature monitoring, and spare parts inventory management. With the referenced strategies, Longview feels that even though the efficiency impact of such a failure is significant, it can be handled in manner to get back to normal condition with appropriate speed to largely mitigate risk of CO2 compliance when averaged over the reporting time period with reasonable compliance margin.

Scenario 2 - High Backpressure and L-0 Removed

One such example is the Low Pressure (LP) Turbine L-0 blading. The L-0 blading on LP Turbine is the final stage of converting steam energy in mechanical energy to be converted to electrical energy at generator. In order to convert as much energy as possible these blades are very long which creates significant stress on the blades due to forces placed on them. Additionally, since this is the last stage of blading, the steam has started to transition into saturation temperatures becoming wet steam; creating an ongoing erosion issue on the leading edges of blades.

Longview Power Emergency Heat Rate Analysis Narrative

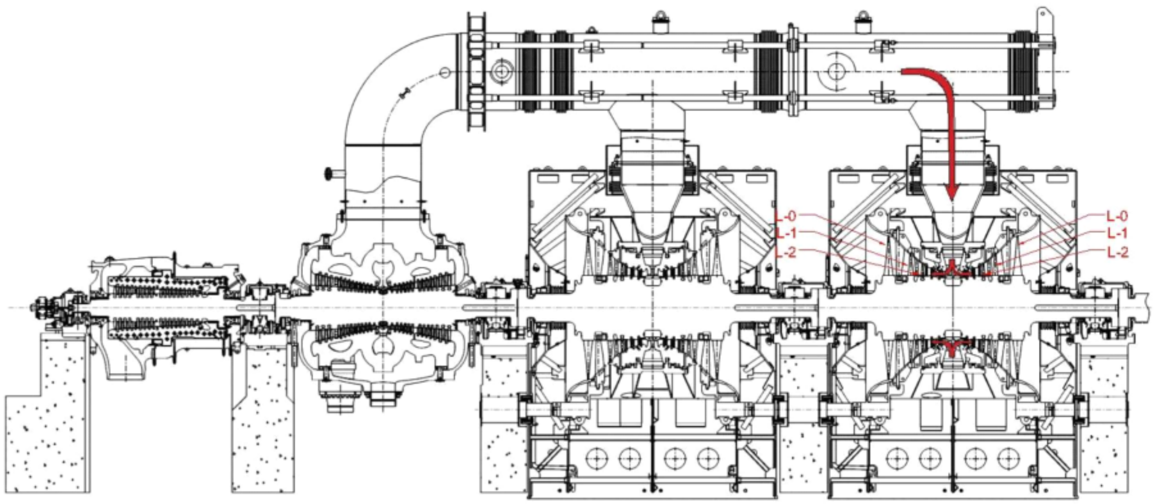


Figure 1: Longview Power Steam Turbine Overview

As you can see in Figure 1, the L-0 blading is the last row of blades and they are the largest blades in system.

L-0 blading (the last rotating row) in LP turbines has been an ongoing industry wide design and reliability issue for OEMs and plant engineers for many years. This row experiences a very unique range of operating conditions that place significant stresses on the material. Longview, as well as most facilities, have an extensive advanced NDE technologies program to monitor the condition of the blading. Longview utilizes an advanced phased array technique approximately every 25,000 hours of operation (approximately every 3 ½ years) or after a turbine trip with loss of condenser vacuum due to additional significant stresses on the LP turbine blading. This effort and expense is completed in hope to identify an issue in very early stage that can be corrected prior to a complete failure event, however it is very feasible to find an indication that would require immediate action or mitigation.

In 2017, Longview experienced a failure of an L-2 LP turbine blade that damaged the entire L-2 row, as well as L-1 and L-0 rows. Inspection required the L-2 and L-1 blading to be replaced. Longview highly contemplated removing L-0 blading due to the damage on blades. If this was required, an approximate 15 - 30% MW load loss and a 14% impact to unit efficiency. This temporary measure will allow continued operation and preservation of some revenue thus maintaining the business until the parts can be supplied. Replacement of L-0 blades would require a 5-6 week long outage. This High Impact scenario results in having to run the unit out of compliance for well over a one year time period and thus will need to be addressed through some reasonable permit relief mechanism.

Longview Power Emergency Heat Rate Analysis Narrative

Scenario 3 – 7/8 HP Heaters Out of Service

There are many cases where it may be required to run without feedwater heaters in service. Depending on the specific heaters or combination of heaters it can have an efficiency impact greater than 2.5%. The unit is designed to operate without these heaters and maintain normal emissions.

Table 1 - Summary of Heat Rate Impacts

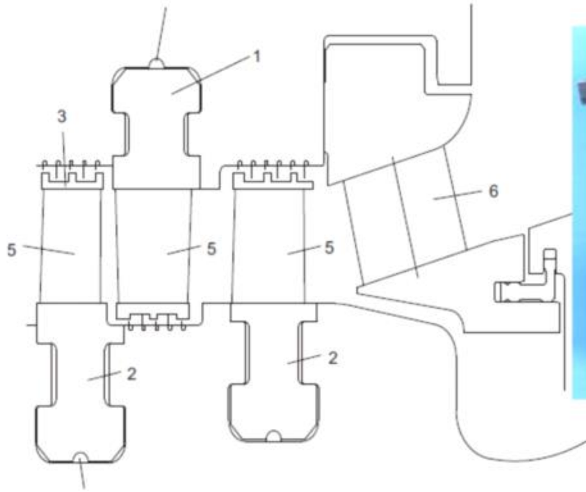
	Baseline Scenario	Scenario 1	Scenario 2	Scenario 3
Unit Heat Rate (Btu/kwh Net)	8,857	9,509	10,241	9,085
Heat Rate Impact	0.0%	7.4%	14.2%	2.6%
% Rated Load	100.0%	93.5%	87.1%	98.1%
Unit Operating Load (MW Net)	700	655	609	686

Conclusion

In conclusion, there are equipment failures that can be reasonably managed via the O&M best practice BSER; however, there are real scenarios that even with world class O&M BSER practices, you can't reasonably mitigate the risk of CO2 compliance issue in event. A relief method needs to be in place to support the ongoing operation of facility with this type of impact, and maintain the economic viability of the unit through minimized downtime. Given the range of efficiency losses calculated from the various failure scenarios, the 110% Level 2 criteria are a realistic and accurate way to compensate both operationally and economically in the event these or similar failure events occur over the life of the unit, while still maintaining a high degree of environmental performance.

Pics of Equipment and Components

Thursday, October 8, 2020 9:04 AM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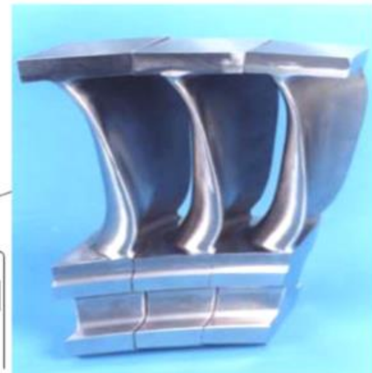
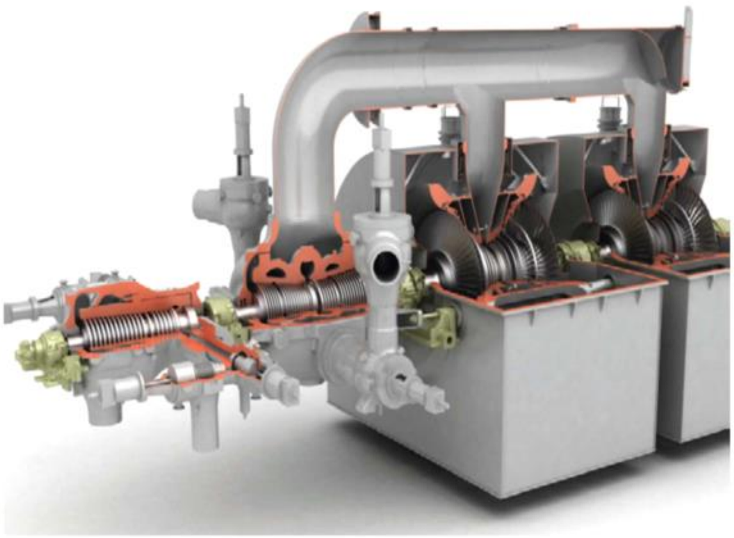




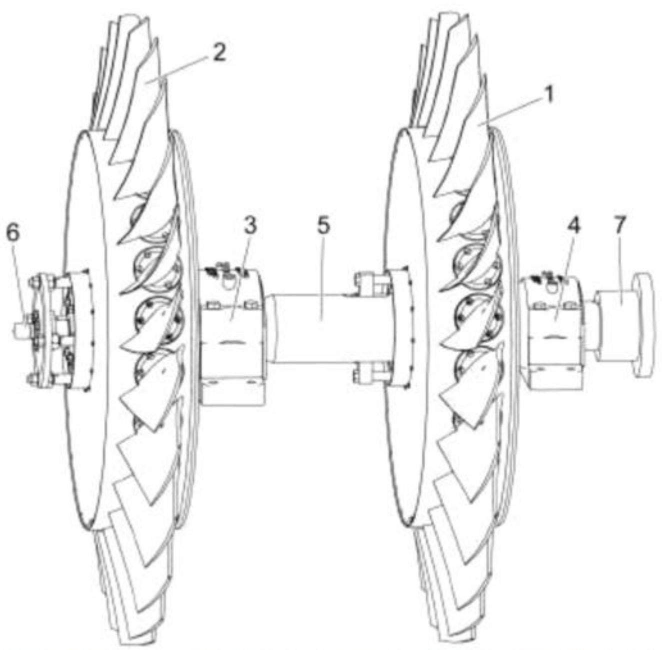
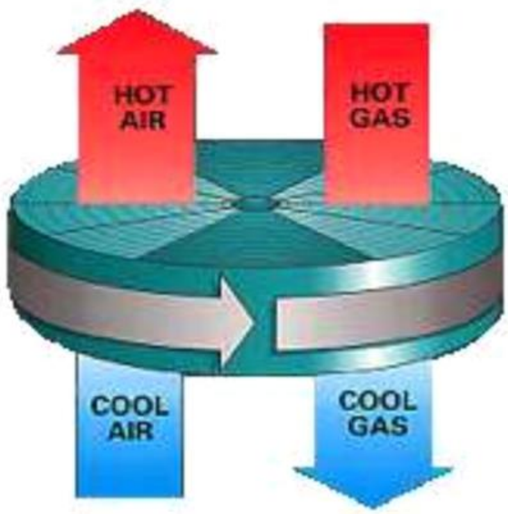


Figure 7. Rotor assembly (basic figure, bearings design may differ)

1. *Impeller 1*
2. *Impeller 2*
3. *Locating (thrust) bearing (type spherical roller bearing)*
4. *Non-locating (free) bearing (type spherical roller bearing)*
5. *Main shaft*
6. *Pitch control mechanism for Impeller 2*
7. *Coupling hub*


HOT
AIR
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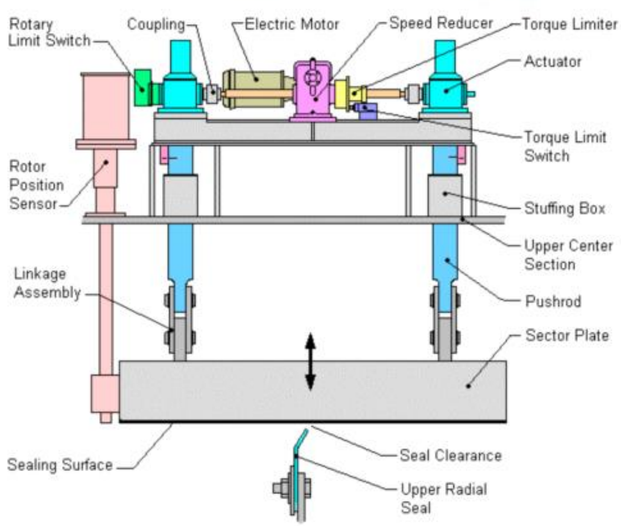
GAS


Rotary
Limit Switch
Coupling
Electric Motor
Speed Reducer
Torque Limiter
Actuator
Torque Limit
Switch
Rotor
Position
Sensor
Stuffing Box
Upper Center
Section
Linkage
Assembly
Pushrod
Sector Plate
Sealing Surface
Seal Clearance
Upper Radial
Seal

Affidavit of Publication

Thursday, October 8, 2020 9:14 AM

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010158671 July 17

AIR QUALITY PERMIT NOTIFICATION
Notice of Application

Notice is given that Longview Power, LLC has applied to the West Virginia Department of Environmental Protection, Division of Air Quality, for a Construction Permit for establishing a carbon dioxide standard for the existing coal fired electric generating unit under the Affordable Clean Energy Rule located on 1375 Fort Martin Rd., Maidsville, in Monongalia County, West Virginia. The latitude and longitude coordinates are: 39.7080, -79.9589

The applicant estimates the potential to discharge the following Regulated Air Pollutants will be:

6,371,980 tpy of Carbon Dioxide

Startup of operation is planned to begin on or about the 8th day of July, 2022. Written comments will be received by the West Virginia Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE, Charleston, WV 25304, for at least 30 calendar days from the date of publication of this notice.

Any questions regarding this permit application should be directed to the DAQ at (304) 926-0499 x41281, during normal business hours.

Dated this the 1st day of July, 2020.

By: Longview Power, LLC
Stephen Nelson
Chief Operating Officer
1375 Fort Martin Rd.
Maidsville, WV 26541

The Dominion Post

1251 Earl L Core Road
Morgantown, WV 26505
(304) 291-9420

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I, **Brad Pennington,** Advertising Director of THE DOMINION POST, a newspaper of general circulation published in the City of Morgantown, County and State aforesaid, do hereby certify that the annexed

Legal Notice

was published in the said THE DOMINION POST once a week for **1** successive weeks commencing on the **17th** day of **July**, **2020** and ending on the **17th** day of **July**, **2020.**

The publisher's fee for said publication is **$62.96**

Given under my hand this **17th** day of **July**, **2020**

Brad Pennington

(SEAL)

Advertising Director of THE DOMINION POST

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Brittany Merrill
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Morgantown, WV 26505
My Commission Expires February 18, 2025

B&V Online Performance Monitoring System (OPM)

Thursday, October 8, 2020 9:15 AM

What is OPM?

Black & Veatch's On-Line Performance Monitoring System (OPM) is a complete software package that helps improve plant operations by recording "Live" data, displaying current operating data quickly and graphically to plant operators, notifying plant operators of off-target operations, and providing plant operators with suggestive actions to improve plant performance. In addition to on-line modeling, OPM has the capability to provide predictive modeling for "what if" analyses of plant operations. This allows for possible changes to equipment and operations to be more accurately considered before implementation.

OPM uses a client/server architecture under Windows and provides a graphical, user-defined operator interface, similar to other windows applications, to allow you to view raw data, playback stored data, perform trending analyses, and create customized reports. OPM provides a permanent record of all measurements, calculations, and averages. Furthermore, the monitoring equipment and instrumentation are not part of OPM, making the system independent of various monitoring methods.

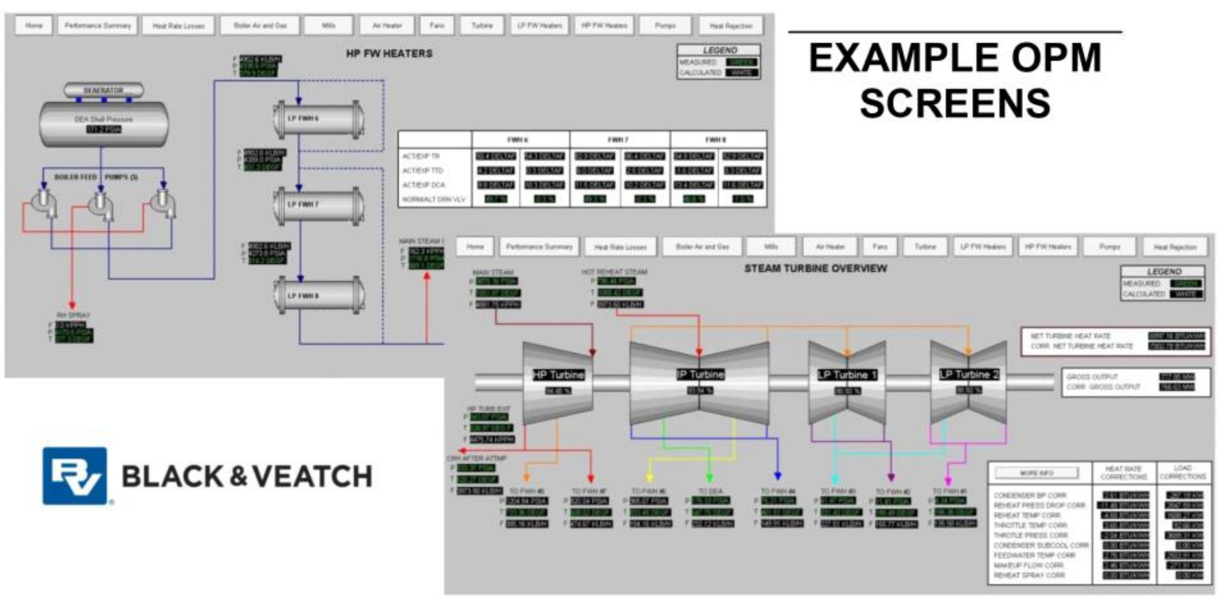
What are the Benefits of OPM?

OPM provides utilities with opportunities to improve operating efficiencies, reduce operating costs, and improve overall plant performance and profitability by allowing you to track plant operations quickly and conveniently. OPM will help the user save money by using less fuel and assist in scheduling maintenance for optimum results. By using this system, you will also realize manpower savings because OPM performs labor-intensive functions such as data retrieval, storage, analysis, equipment testing, and reporting. OPM offers a reliable, user-friendly, and cost-effective approach to improving plant operations and performance.

Who Uses OPM?

Plant operators, plant maintenance personnel, performance engineers, fuels engineers, environmental engineers, planning engineers, and plant managers are frequent users of OPM.

EXAMPLE OPM SCREENS



BLACK & VEATCH

Statement of Basis for Longview Power Coal Adjustment Factor

Thursday, October 8, 2020 9:24 AM

STATEMENT OF BASIS FOR LONGVIEW POWER COAL ADJUSTMENT FACTOR

Introduction

Longview Power has prepared this document to provide the technical and regulatory basis for the WVDEP to rely upon as they derive the CO_2 standard of performance to apply at the Longview Power Plant as part of the first-phase/segmented ACE State Plan anticipated to be submitted by the State of West Virginia to EPA. What follows is an explanation of the technical methodology and regulatory support for a self-implementing coal quality adjustment factor to the standard of performance that will otherwise apply at the Longview Power Plant through a federally enforceable special condition in a WVDEP-issued Reg 13 Air Permit. Before setting out the proposed technical approach and pertinent regulatory authorities, the remainder of this introduction will address two key issues that have played heavily into why Longview Power is proposing this methodology.

Need for Coal Quality Flexibility

Thermal power plant operations costs are significantly dominated by fuel costs, which typically represent 70 to 80% of total cost of operations. Inherent in the fuel cost are the cost of fuel production, transportation and the conversion (converting the chemical energy into electrical energy – unit heat rate) efficiency. Additionally, power plants are designed to consume fuels within a specific range of the various fuel characteristics and thus have limits as to what can be burnt. An overriding fact of fuel production/supply especially with coal is that the economics of extraction and transportation can change significantly with time, geologic conditions, broader economic conditions, government policies and overall thermal coal production volumes. From these factors it is critical for each facility to maintain viable fuel resources that fit into its specific design parameters as controlling fuel cost becomes a key driver to the overall cost effectiveness of producing affordable electric power.

The concept of accounting for fuel rank is a long-established and judicially-approved approach in the development of emission standards for power plants.[1] Here, where EPA chooses to defer to the states to develop site-specific standards of performance in lieu of developing national subcategories as part of its BSER determination, it is essential that EPA allow states great latitude to account for the real-world variability of fuel supply that might come into play at a given site. It is equally important that EPA recognize that few, if any, power plants will have the luxury of knowing they will need to switch fuel supplies 18-24 months in advance (which is the approximate time it would take to get an ACE State Plan revision proposed, finalized, and approved by EPA). Given these two fundamentals, Longview and the WVDEP have been exploring options for a coal adjustment factor that could be hard-wired into Longview's permit and, by incorporation, the State of West Virginia's ACE State Plan. What follows is a full discussion of what has been considered

[1] *See, e.g.,* National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units.77 Fed. Reg. 9,304, 9367 (Feb. 16, 2012) (codified at 40 C.F.R.§ 63.9990)(Mercury and Air Toxic Standard (MATS) Subcategorization of fuel ranks).

and ruled out and what Longview believes is the most technically defensible and legally sound approach to tackle this issue.

Part 75 Appendix G Fuel Equation & CO_2 Prediction

During calls held between and among EPA, WVDEP, and Longview, one potential option for a fuel adjustment factor that was explored was the utilization of an equation in Part 75 Appendix G that plays a role in how CO_2 CEMS data can be adjusted based on the carbon content of the fuel. After extensive evaluation of this option, Longview has come to the conclusion that this Appendix G equation simply could not be validated as an appropriate coal adjustment factor either using past or current fuels. It is simply too simplistic and does not adequately model all the factors in determining unit CO_2 at the necessary level of accuracy. CO_2 levels predicted by the model varied from measured CO_2 levels by approximately +/ 10% on a monthly basis. This is far too great a variance to determine CO_2 limits given the very tight compliance margin contemplated in Longview's Rule 13 permit. This approach in predicting CO_2 performance is not feasible for our purposes.

Pollution Control Strategy versus Pollution Control Equipment

There is no ancillary equipment that can be turned up or chemicals that can be added to enhance CO_2 performance or Heat Rate once the Heat Rate Improvement (HRI) BSER technologies are in-place and well-maintained. Changes in fuel source drive the CO_2 output given all other factors remaining the same. To ensure that the ACE Rule does not violate the fundamental Clean Air Act principal that EPA not redefine the source, EPA ensured in the final ACE rule that the standard of performance to be derived by states for a site must target the most efficient operation possible given the fuel being utilized at a given site and, by extension, not dictate the fuel to be run. Therefore, while an EGU must run as efficiently as possible (while still maintaining safe and reliable operation) via the implementation of the HRI BSER, the CO_2 standard of performance cannot limit what fuel is run by the unit, and therefore a mechanism must be put in place to automatically adjust the CO_2 standard of performance based on the emissions impact of a change in coal source. What follows is the most technically-sound methodology Longview has been able to identify after exploring several options for an appropriate, self-implementing coal adjustment factor.

Discussion

Technical Overview of Proposed Coal Adjustment Factor (CAF)

The most viable technical basis for a self-implementing coal adjustment factor (CAF) is to establish a formal protocol for deriving a percentage adjustment to the standard of performance based on a test burn which is to be used in the event of a change in coal supply. That protocol should begin with a 4-week test burn governed by a formal "Test Burn Protocol (TBP)" which outlines the test burn timeline, procedures, methods, deliverables, etc. This TBC would generally fill the same role as a RATA Protocol. It would essentially say that over the burn timing, Longview would have all applicable HRI BSER in place and properly maintained and utilize the real-time heat rate, and other instrumentation, to optimize the unit efficiency on the test fuel as appropriate when considering efficiency (Heat Rate & CO_2 Performance), safety, and reliability. An appropriately credentialed 3rd party certifying entity will be required to conduct the monitoring and analysis to assist in unit efficiency tuning. The protocol would be reviewed and approved by WVDAQ prior to the burn. Based on the certified results of the test burn, Longview would demonstrate the need (or lack thereof) of a percentage adjustment to the CO_2 performance standard. For instance, if week 4 data showed that the fuel was 3% above the Bin 5 standard for the particular year the burn occurred, then the standard of performance would be increased by 3% across all bins for the years moving forward. Degradation would be applied the same moving forward. Week 4 would be the most optimized performance given a 4 week test burn and would therefore be the most representative of long-term performance. A "Max Daily Average + 2 SD" approach would be used although the time periods would obviously differ from the baseline assessment of "Max Rolling 12 Month Averages + 2SD."

Regulatory Basis for the Proposed Coal Adjustment Factor (CAF)

The proposed CAF outlined herein satisfies the letter of the ACE Rule requirements and the implementing regulations governing Section 111(d) standards. Moreover, the proposed CAF is entirely consistent with the expressed intent of the ACE Rule through numerous preamble statements made by EPA.

The ACE Rule provisions broadly require that State Plans include a "standard of performance" for covered facilities.[2] The ACE Rule further provides that "[t]he standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh)."[3] The ACE Rule further provides that:

> *In establishing any standard of performance, you must consider the applicability of each of the heat rate improvements and associated degree of emission limitation achievable included in § 60.5740a(a)(1) and (2) to the designated facility. You must include a demonstration in your plan submission for how you considered each heat rate improvement and associated degree of emission limitation achievable in calculating each standard of performance.*
>
> > *(i) In applying a standard of performance to any designated facility, you may consider the source-specific factors included in § 60.24a(e).*
> >
> > *(ii) If you consider source-specific factors to apply [sic.] a standard of performance, you must include a demonstration in your plan submission for how you considered such factors.*[4]

The ACE Rule further requires that the standard of performance meet four criteria – that it be demonstrated to be: (1) quantifiable; (2) verifiable; (3) permanent; and (4) enforceable.[5] A State Plan must include the methods by which a standard of performance meets each of these requirements as follows:

[2] 40 C.F.R. § 60.5775a(a).
[3] 40 C.F.R. § 60.5775a(a)(1).
[4] *Id.* § 60.5775a(a)(2).
[5] *Id.* § 60.5775a(b).

(i) A designated facility's standard of performance is <u>quantifiable</u> if it can be reliably measured in a manner that can be replicated.

(ii) A designated facility's standard of performance is <u>verifiable</u> if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and [EPA] to independently evaluate, measure, and verify compliance with the standard of performance.

(iii) A designated facility's standard of performance is <u>permanent</u> if the standard of performance must be met for each compliance period, unless it is replaced by another standard of performance in an approved plan revision; and

(iv) A designated facility's standard of performance is <u>enforceable</u> if:

> *(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;*
>
> *(2) Compliance requirements are clearly defined;*
>
> *(3) The designated facility responsible for compliance and liable for violations can be identified;*
>
> *(4) Each compliance activity or measure is enforceable as a practical matter; and*
>
> *(5) [EPA], the State, and third parties maintain the ability to enforce against violations (including if a designated facility does not meet its standard of performance based on its emissions) and secure appropriate corrective actions ....*[6]

EPA in its final preamble promulgating the ACE Rule recognized issues posed by operational variability, including fuel usage, and granted the states great deference in resolving such issues. To account for variability in emissions, EPA noted in its ACE Rule Response to Comments that:

The EPA agrees that consideration of unit-specific duty cycles and averaging times are important aspects of establishing numerical emission limits (standards of performance). In establishing the standards of performance, the states will also have the flexibility to take unit specific factors (such as projected duty cycle) into account, so long as they exercise their discretion in a reasonable and adequately explained manner. The states also have the option to define operating parameters for the numerical emission limits. For example, the emission standard may specify that the compliance measurement be done at a specific load and under specific conditions.[7]

The EPA has provided non-binding, illustrative examples ... to assist and demonstrate to states some of the options in developing plans. A model rule would not be particularly useful for states as it would have to make many assumptions about state-specific factors and source-specific factors that would not apply to many states and situations. By providing broad flexibility to states, states can

[6] *Id.* § 60.5775a(c)-(f) (emphasis added).
[7] EPA, Response to Public Comments on the EPA's Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (hereinafter "RTC") (June 2018) § 3.1 (available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-26741).

develop a plan and program that best fits the situation and factors unique to the state and sources.[8]

[S]tates have considerable flexibility in the development of state plans for the implementation of ACE. Under this rule, states have it within their authority to consider variability in emissions in the development of their plan, including in the establishment of standards of performance and measures that provide for the implementation and enforcement of such standards. It is within the states' discretion how to consider variability in emissions, as long as their approach is reasonable and adequately explained. The EPA has provided non-binding examples in the preamble to address issues and/or requirements such as this.[9]

EPA recognized issues posed by variability in emission performance, both between different facilities and also at individual facilities with numerous operating variables. In particular, EPA noted that:

[S]tandards of performance should reflect variability in emission performance at an individual designated facility due to changes in operating conditions. Specifically, the agency believes it would be appropriate for states to identify key factors that influence unit level emission performance (e.g., load, maintenance schedules, and weather) and to establish emission standards that vary in accordance with those factors. In other words, states could establish standards of performance for an individual EGU that vary (i.e., differ) as factors underlying emission performance vary. For example, states could identify load segments (ranges of EGU load operation) that reflect consistent emission performance within the segment and varying emission performance between segments. States could then establish standards of performance for an EGU that differ by load segment. Another possible option to account for variable emissions is to set standards of performance based on a standard set of conditions. A state could establish a baseline of performance of a unit at specific load and operational conditions and then set a standard against those conditions via the application of the BSER. Compliance for the unit could be demonstrated annually (or by another increment of time if appropriate based on the level of stringency of the standard of performance set for the unit) at those same conditions. In the interim, between the demonstration of compliance under standardized conditions, a state could allow for the maintenance and demonstration of fully operational candidate technologies to be a method to demonstrate compliance as the standard of performance must apply at all times.[10]

The reference to the ability to rely upon the operation and maintenance of BSER HRI in between performance tests is directly analogous to the ability to rely upon the same thing as the standard of performance during the pendency of the test burn in the CAF concept being proposed here.

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[8] *Id.* § 5.5.1.
[9] *Id.* § 6.2.
[10] 84 Fed. Reg. 32520, 32552 (July 8, 2019)(emphasis added).

The concept that adjustment could be made to the standard of performance to account for varying conditions is expressly endorsed by EPA when it endorsed the concept of differing emission standards for different load segments and EPA left open to the discretion of the states to come up with other analogous concepts:

> *The Agency believes that these approaches to providing flexibility (and possible others not described here) in establishing standards of performance are reasonable and appropriate by accounting for innate variable emission performance across EGUs and at specific EGUs while also limiting this flexibility to instances in which underlying variable factors are evaluated and linked to variable emission performance.*[11]

It is expected that the CAF and accompanying TBP outlined above would yield a quantifiable, verifiable, permanent, and enforceable standard of performance in the form of an emission rate stated in terms of pounds of CO2 emitted per MWh with a percentage adjustment factor available in the event that a change in coal supply is necessary and the prescribed TBP is followed.

Using an established TBP will ensure that the performance standard remains quantifiable in a reliable and replicable manner because it would be conducted pursuant to tightly bound protocols and certified by credentialed third party experts. It would be verifiable in that there would be adequate monitoring, recordkeeping and reporting requirements that would ensure regulatory authorities could verify compliance with both the initial performance standard, the detailed TBP, and the resulting percentage adjustment to the performance standard for the new coal source. Third, the CAF-adjusted standard of performance would be permanent in that it would governed by explicit, federally-enforceable permit conditions that would codify (1) the initial standard of performance, (2) the TBP and (3) the resulting standard of performance adjustment percentage. No change to any one of these three components of the standard of performance would be allowed without a formal State Plan revision. Finally, the standard of performance would be enforceable as it would be a clearly-specified limitation contained in a federally-enforceable state-issued permit condition.

Conclusion

Based on the technical and regulatory basis set out in detail above, Longview respectfully submits that the CAF and accompanying TBP can be implemented by the WVDEP under its primary role in developing site-specific standards of performance for sources governed by the ACE Rule. Both the Reg 13 permit conditions that will set out the parameters of the CAF and TBP, as well as the EPA's concurrence in these federally-enforceable parameters, more than adequately satisfy the requirements of 40 CFR § 60.5775a because this standard of performance and accompanying adjustment factors and protocols are quantifiable, verifiable, permanent, and enforceable, as fully described above. Moreover, the WVDEP fully supports the CAF and accompanying TBP and the State of West Virginia's has clear authority and, in fact, primacy in the ACE Rule to account for site-

[11] *Id.* (emphasis added).

specific and fuel-appropriate conditions in the derivation of the standard of performance to apply to governed facilities.

Revised Statement of Basis for LVP CAF

Thursday, October 8, 2020 9:26 AM

STATEMENT OF BASIS FOR LONGVIEW POWER COAL ADJUSTMENT FACTOR

Introduction

Longview Power has prepared this document to provide the technical and regulatory basis for the WVDEP to rely upon as they derive the CO_2 standard of performance to apply at the Longview Power Plant as part of the first-phase/segmented ACE State Plan anticipated to be submitted by the State of West Virginia to EPA. What follows is an explanation of the technical methodology and regulatory support for a self-implementing coal quality adjustment factor to the standard of performance that will otherwise apply at the Longview Power Plant through a federally enforceable special condition in a WVDEP-issued Reg 13 Air Permit. Before setting out the proposed technical approach and pertinent regulatory authorities, the remainder of this introduction will address two key issues that have played heavily into why Longview Power is proposing this methodology.

Need for Coal Quality Flexibility

Thermal power plant operations costs are significantly dominated by fuel costs, which typically represent 70 to 80% of total cost of operations. Inherent in the fuel cost are the cost of fuel production, transportation and the conversion (converting the chemical energy into electrical energy – unit heat rate) efficiency. Additionally, power plants are designed to consume fuels within a specific range of the various fuel characteristics and thus have limits as to what can be burnt. An overriding fact of fuel production/supply especially with coal is that the economics of extraction and transportation can change significantly with time, geologic conditions, broader economic conditions, government policies and overall thermal coal production volumes. From these factors it is critical for each facility to maintain viable fuel resources that fit into its specific design parameters as controlling fuel cost becomes a key driver to the overall cost effectiveness of producing affordable electric power.

The concept of accounting for fuel rank is a long-established and judicially-approved approach in the development of emission standards for power plants. Here, where EPA chooses to defer to the states to develop site-specific standards of performance in lieu of developing national subcategories as part of its BSER determination, it is essential that EPA allow states great latitude to account for the real-world variability of fuel supply that might come into play at a given site. It is equally important that EPA recognize that few, if any, power plants will have the luxury of knowing they will need to switch fuel supplies 18-24 months in advance (which is the approximate time it would take to get an ACE State Plan revision proposed, finalized, and approved by EPA). Given these two fundamentals, Longview and the WVDEP have been exploring options for a coal adjustment factor that could be hard-wired into Longview's permit and, by incorporation, the State of West Virginia's ACE State Plan. What follows is a full discussion of what has been considered and ruled out and what Longview believes is the most technically defensible and legally sound approach to tackle this issue.

Part 75 Appendix G Fuel Equation & CO_2 Prediction

During calls held between and among EPA, WVDEP, and Longview, one potential option for a fuel adjustment factor that was explored was the utilization of an equation in Part 75 Appendix G that plays a role in how CO_2 CEMS data can be adjusted based on the carbon content of the fuel. After extensive evaluation of this option, Longview has come to the conclusion that this Appendix G equation simply could not be validated as an appropriate coal adjustment factor either using past or current fuels. It is simply too simplistic and does not adequately model all the factors in determining unit CO_2 at the necessary level of accuracy. CO_2 levels predicted by the model varied from measured CO_2 levels by approximately +/ 10% on a monthly basis. This is far too great a variance to determine CO_2 limits given the very tight compliance margin contemplated in Longview's Rule 13 permit. This approach in predicting CO_2 performance is not feasible for our purposes.

Pollution Control Strategy versus Pollution Control Equipment

There is no ancillary equipment that can be turned up or chemicals that can be added to enhance CO_2 performance or Heat Rate once the Heat Rate Improvement (HRI) BSER technologies are in-place and well-maintained. Changes in fuel source drive the CO_2 output given all other factors remaining the same. To ensure that the ACE Rule does not violate the fundamental Clean Air Act principal that EPA not redefine the source, EPA ensured in the final ACE rule that the standard of performance to be derived by states for a site must target the most efficient operation possible given the fuel being utilized at a given site and, by extension, not dictate the fuel to be run. Therefore, while an EGU must run as efficiently as possible (while still maintaining safe and reliable operation) via the implementation of the HRI BSER, the CO_2 standard of performance cannot limit what fuel is run by the unit, and therefore a mechanism must be put in place to automatically adjust the CO_2 standard of performance based on the emissions impact of a change in coal source. What follows is the most technically-sound methodology Longview has been able to identify after exploring several options for an appropriate, self-implementing coal adjustment factor.

Discussion

Technical Overview of Proposed Coal Adjustment Factor (CAF)

The most viable technical basis for a self-implementing coal adjustment factor (CAF) is to establish a formal protocol for deriving a percentage adjustment to the standard of performance based on a test burn which is to be used in the event of a change in coal supply. That protocol should begin with a 4-week test burn governed by a formal "Test Burn Protocol (TBP)" which outlines the test burn timeline, procedures, methods, deliverables, etc. This TBC would generally fill the same role as a RATA Protocol. It would essentially say that over the burn timing, Longview would have all applicable HRI BSER in place and properly maintained and utilize the real-time heat rate, and other instrumentation, to optimize the unit efficiency on the test fuel as appropriate when considering efficiency (Heat Rate & CO_2 Performance), safety, and reliability. An appropriately credentialed 3rd party certifying entity will be required to conduct the monitoring and analysis to assist in unit efficiency tuning. The protocol would be reviewed and approved by WVDAQ prior to the burn. Based on the certified results of the test burn, Longview would demonstrate the need (or lack thereof) of a percentage adjustment to the CO_2 performance standard. For instance, if week 4 data showed that the fuel was 3% above the Bin 5 standard for the particular year the burn occurred, then the standard of performance would be increased by 3% across all bins for the years moving forward. Degradation would be applied the same moving forward. Week 4 would be the most optimized performance given a 4 week test burn and would therefore be the most representative of long-term performance. A "Max Daily Average + 2 SD" approach would be used although the time periods would obviously differ from the baseline assessment of "Max Rolling 12 Month Averages + 2SD."

<u>Regulatory Basis for the Proposed Coal Adjustment Factor (CAF)</u>

1. Primary Role of State in Deriving the Standard of Performance

INSERT STATE PRIMACY AND LIMITS TO FEDERAL SECOND-GUESSING – REFERENCE THE FACT THAT EPA DID NOT CREATE SUBCATEGORIES FOR FUEL RANKS DESPITE LONG HISTORY OF DOING SO GIVEN UNIQUE ROLE OF STATES IN THE ACCOUNTING OF SUCH FACTORS

2. Specific ACE Regulatory and Preamble Basis for Proposed CAF

The proposed CAF outlined herein satisfies the letter of the ACE Rule requirements and the implementing regulations governing Section 111(d) standards. Moreover, the proposed CAF is entirely consistent with the expressed intent of the ACE Rule through numerous preamble statements made by EPA.

The ACE Rule provisions broadly require that State Plans include a "standard of performance" for covered facilities.[1] The ACE Rule further provides that "[t]he standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh)."[2] The ACE Rule further provides that:

> *In establishing any standard of performance, you must consider the applicability of each of the heat rate improvements and associated degree of emission limitation achievable included in § 60.5740a(a)(1) and (2) to the designated facility. You must include a demonstration in your plan submission for how you considered each heat rate improvement and associated degree of emission limitation achievable in calculating each standard of performance.*
>
> > *(i) In applying a standard of performance to any designated facility, you may consider the source-specific factors included in § 60.24a(e).*

[1] 40 C.F.R. § 60.5775a(a).
[2] 40 C.F.R. § 60.5775a(a)(1).

> *(ii) If you consider source-specific factors to apply [sic.] a standard of performance, you must include a demonstration in your plan submission for how you considered such factors.*[3]

The ACE Rule further requires that the standard of performance meet four criteria – that it be demonstrated to be: (1) quantifiable; (2) verifiable; (3) permanent; and (4) enforceable.[4] A State Plan must include the methods by which a standard of performance meets each of these requirements as follows:

> *(i) A designated facility's standard of performance is <u>quantifiable</u> if it can be reliably measured in a manner that can be replicated.*
>
> *(ii) A designated facility's standard of performance is <u>verifiable</u> if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and [EPA] to independently evaluate, measure, and verify compliance with the standard of performance.*
>
> *(iii) A designated facility's standard of performance is <u>permanent</u> if the standard of performance must be met for each compliance period, unless it is replaced by another standard of performance in an approved plan revision; and*
>
> *(iv) A designated facility's standard of performance is <u>enforceable</u> if:*
>
>> *(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;*
>>
>> *(2) Compliance requirements are clearly defined;*
>>
>> *(3) The designated facility responsible for compliance and liable for violations can be identified;*
>>
>> *(4) Each compliance activity or measure is enforceable as a practical matter; and*
>>
>> *(5) [EPA], the State, and third parties maintain the ability to enforce against violations (including if a designated facility does not meet its standard of performance based on its emissions) and secure appropriate corrective actions ....*[5]

EPA in its final preamble promulgating the ACE Rule recognized issues posed by operational variability, including fuel usage, and granted the states great deference in resolving such issues. To account for variability in emissions, EPA noted in its ACE Rule Response to Comments that:

> *The EPA agrees that consideration of unit-specific duty cycles and averaging times are important aspects of establishing numerical emission limits (standards of performance). In establishing the standards of performance, the states will also have the flexibility to take unit specific factors (such as projected duty cycle) into account, so long as they exercise their discretion in a reasonable and adequately explained manner. The states also have the option to define operating parameters for the*

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[3] *Id.* § 60.5775a(a)(2).
[4] *Id.* § 60.5775a(b).
[5] *Id.* § 60.5775a(c)-(f) (emphasis added).

numerical emission limits. For example, the emission standard may specify that the compliance measurement be done at a specific load and under specific conditions.[6]

The EPA has provided non-binding, illustrative examples ... to assist and demonstrate to states some of the options in developing plans. A model rule would not be particularly useful for states as it would have to make many assumptions about state-specific factors and source-specific factors that would not apply to many states and situations. By providing broad flexibility to states, states can develop a plan and program that best fits the situation and factors unique to the state and sources.[7]

[S]tates have considerable flexibility in the development of state plans for the implementation of ACE. Under this rule, states have it within their authority to consider variability in emissions in the development of their plan, including in the establishment of standards of performance and measures that provide for the implementation and enforcement of such standards. It is within the states' discretion how to consider variability in emissions, as long as their approach is reasonable and adequately explained. The EPA has provided non-binding examples in the preamble to address issues and/or requirements such as this.[8]

EPA recognized issues posed by variability in emission performance, both between different facilities and also at individual facilities with numerous operating variables. In particular, EPA noted that:

[S]tandards of performance should reflect variability in emission performance at an individual designated facility due to changes in operating conditions. Specifically, the agency believes it would be appropriate for states to identify key factors that influence unit level emission performance (e.g., load, maintenance schedules, and weather) and to establish emission standards that vary in accordance with those factors. In other words, states could establish standards of performance for an individual EGU that vary (i.e., differ) as factors underlying emission performance vary. For example, states could identify load segments (ranges of EGU load operation) that reflect consistent emission performance within the segment and varying emission performance between segments. States could then establish standards of performance for an EGU that differ by load segment. Another possible option to account for variable emissions is to set standards of performance based on a standard set of conditions. A state could establish a baseline of performance of a unit at specific load and operational conditions and then set a standard against those conditions via the application of the BSER. Compliance for the unit could be demonstrated annually (or by another increment of time if appropriate based on the level of stringency of the standard of

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[6] EPA, Response to Public Comments on the EPA's Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (hereinafter "RTC") (June 2018) § 3.1 (available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-26741).
[7] *Id.* § 5.5.1.
[8] *Id.* § 6.2.

> *performance set for the unit) at those same conditions. In the interim, between the demonstration of compliance under standardized conditions, a state could allow for the maintenance and demonstration of fully operational candidate technologies to be a method to demonstrate compliance as the standard of performance must apply at all times.*[9]

The reference to the ability to rely upon the operation and maintenance of BSER HRI in between performance tests is directly analogous to the ability to rely upon the same thing as the standard of performance during the pendency of the test burn in the CAF concept being proposed here.

The concept that adjustment could be made to the standard of performance to account for varying conditions is expressly endorsed by EPA when it endorsed the concept of differing emission standards for different load segments and EPA left open to the discretion of the states to come up with other analogous concepts:

> *The Agency believes that these approaches to providing flexibility (and possible others not described here) in establishing standards of performance are reasonable and appropriate by accounting for innate variable emission performance across EGUs and at specific EGUs while also limiting this flexibility to instances in which underlying variable factors are evaluated and linked to variable emission performance.*[10]

It is expected that the CAF and accompanying TBP outlined above would yield a quantifiable, verifiable, permanent, and enforceable standard of performance in the form of an emission rate stated in terms of pounds of CO2 emitted per MWh with a percentage adjustment factor available in the event that a change in coal supply is necessary and the prescribed TBP is followed.

Using an established TBP will ensure that the performance standard remains quantifiable in a reliable and replicable manner because it would be conducted pursuant to tightly bound protocols and certified by credentialed third party experts. It would be verifiable in that there would be adequate monitoring, recordkeeping and reporting requirements that would ensure regulatory authorities could verify compliance with both the initial performance standard, the detailed TBP, and the resulting percentage adjustment to the performance standard for the new coal source. Third, the CAF-adjusted standard of performance would be permanent in that it would governed by explicit, federally-enforceable permit conditions that would codify (1) the initial standard of performance, (2) the TBP and (3) the resulting standard of performance adjustment percentage. No change to any one of these three components of the standard of performance would be allowed without a formal State Plan revision. Finally, the standard of performance would be enforceable as it would be a clearly-specified limitation contained in a federally-enforceable state-issued permit condition.

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[9] 84 Fed. Reg. 32520, 32552 (July 8, 2019)(emphasis added).
[10] *Id.* (emphasis added).

Conclusion

Based on the technical and regulatory basis set out in detail above, Longview respectfully submits that the CAF and accompanying TBP can be implemented by the WVDEP under its primary role in developing site-specific standards of performance for sources governed by the ACE Rule. Both the Reg 13 permit conditions that will set out the parameters of the CAF and TBP, as well as the EPA's concurrence in these federally-enforceable parameters, more than adequately satisfy the requirements of 40 CFR § 60.5775a because this standard of performance and accompanying adjustment factors and protocols are quantifiable, verifiable, permanent, and enforceable, as fully described above. Moreover, the WVDEP fully supports the CAF and accompanying TBP and the State of West Virginia's has clear authority and, in fact, primacy in the ACE Rule to account for site-specific and fuel-appropriate conditions in the derivation of the standard of performance to apply to governed facilities.

Fuel Change Trigger

Thursday, October 8, 2020 9:36 AM

Fuel Change Trigger

Specification (As Received)	Monthly Typical Weighted Average Quality	Significant Fuel Change Triggers
Btu/lb	13,000	<12,500
Sulfur %	3.00%	>3.25%
Ash %	8.75%	>12%
Moisture %	7.00%	>8.50%
Chlorine %	0.10%-0.15%	>0.15%
Nitrogen %	1.55%-1.75%	>1.55%
HGI	>50	<45
Initial Deformation (reducing)	2100F-2150F	<2075F
Softening (reducing)	2200F	<2100F
Initial Deformation (oxidizing)	2375F	<2250F
Softening (oxidizing)	2470F	<2300F
Size	2 X 0	>2.5 x 0

2020 thru June gross and net MW

Thursday, October 8, 2020 9:36 AM

2020 thru June gross and net MW

1/1/2020					
7/1/2020					
1h		10MKA01CE903.XQ02	10CFE00CJ010.ZJ01	CALRevMeterB	1OPM.CONLOSS:NETPLANTHR_HL
	01-Jan-20 00:00:00	772.9702418	772.8549339	697.8627048	8533.502387
	01-Jan-20 01:00:00	774.1809197	774.1921906	698.9957233	8523.842594
	01-Jan-20 02:00:00	772.9210861	772.2736021	697.3037591	8572.283289
	01-Jan-20 03:00:00	773.6292605	773.5750266	698.0245744	8545.845637
	01-Jan-20 04:00:00	773.9758052	773.6014458	698.334037	8535.420559
	01-Jan-20 05:00:00	773.6324621	773.8526792	698.782197	8520.021424
	01-Jan-20 06:00:00	773.6725035	773.0772683	698.4097545	8527.200129
	01-Jan-20 07:00:00	774.857472	774.5868249	698.5776804	8527.538495
	01-Jan-20 08:00:00	771.5991378	771.6658562	695.7222405	8558.674016
	01-Jan-20 09:00:00	761.3270308	760.9050925	686.4013857	8568.238341
	01-Jan-20 10:00:00	774.2730768	774.1050618	698.6545763	8526.149808
	01-Jan-20 11:00:00	772.2513461	772.7646956	696.8277105	8538.51199
	01-Jan-20 12:00:00	755.5634882	756.0320233	682.1882799	8558.583094
	01-Jan-20 13:00:00	731.9631599	731.9592938	659.6895744	8597.285025
	01-Jan-20 14:00:00	711.5883411	711.829905	642.7184718	8560.306888
	01-Jan-20 15:00:00	680.5537896	680.6844835	615.4076803	8578.147312
	01-Jan-20 16:00:00	724.2921617	724.0561419	653.5526205	8636.108076
	01-Jan-20 17:00:00	773.6607146	773.354394	699.959328	8521.947567
	01-Jan-20 18:00:00	774.2801184	773.8784524	699.1798802	8556.057335
	01-Jan-20 19:00:00	773.4692788	773.9685905	698.9213959	8537.029091
	01-Jan-20 20:00:00	774.8938869	775.4518739	700.912853	8529.128304
	01-Jan-20 21:00:00	774.2494348	774.6791594	700.8673622	8514.111985
	01-Jan-20 22:00:00	774.7292703	775.1489785	701.1939403	8555.405114
	01-Jan-20 23:00:00	774.594685	774.2414545	700.8067939	8538.529774
	02-Jan-20 00:00:00	774.527503	774.2818011	699.9199899	8533.84041
	02-Jan-20 01:00:00	775.6887782	775.7552416	701.9438845	8497.350748
	02-Jan-20 02:00:00	774.2899766	773.8962787	701.2719616	8510.156882
	02-Jan-20 03:00:00	774.038524	774.308366	698.6028745	8552.434661
	02-Jan-20 04:00:00	774.8239766	774.7428888	699.1685435	8548.505967
	02-Jan-20 05:00:00	774.1509168	774.8222675	698.9631534	8532.269741
	02-Jan-20 06:00:00	773.7312816	773.4171483	697.7964428	8565.205974
	02-Jan-20 07:00:00	774.4561407	774.657534	699.4611205	8548.465085
	02-Jan-20 08:00:00	772.7390529	773.1198454	696.7226106	8540.663675
	02-Jan-20 09:00:00	774.9734243	774.8450572	699.1657201	8536.497102
	02-Jan-20 10:00:00	775.3365037	775.8831253	699.1984254	8515.986061
	02-Jan-20 11:00:00	775.1859423	775.7101682	698.8814671	8534.592245
	02-Jan-20 12:00:00	775.3462263	774.7919761	699.2983393	8523.142894
	02-Jan-20 13:00:00	776.8300986	776.9345892	701.5182856	8485.511536
	02-Jan-20 14:00:00	776.4369276	776.2545253	700.8514781	8473.709544
	02-Jan-20 15:00:00	776.3958541	776.6661599	701.908518	8514.877542
	02-Jan-20 16:00:00	774.9867553	775.259752	700.5796881	8533.194631
	02-Jan-20 17:00:00	775.9281227	775.9579161	700.7466292	8513.510689
	02-Jan-20 18:00:00	775.8174208	776.5985229	700.9753257	8498.64527
	02-Jan-20 19:00:00	775.9927009	775.9325027	702.5434677	8467.167131
	02-Jan-20 20:00:00	776.7038686	777.5337546	702.9004048	8472.378329
	02-Jan-20 21:00:00	774.7352701	774.1893735	700.2314901	8519.310642
	02-Jan-20 22:00:00	775.2675729	776.0141753	700.8573004	8551.835365
	02-Jan-20 23:00:00	777.1029139	777.1204126	701.565444	8524.799629
	03-Jan-20 00:00:00	775.1874228	775.5724379	700.2852416	8503.097399
	03-Jan-20 01:00:00	776.6235477	776.7598668	702.0832438	8531.998059
	03-Jan-20 02:00:00	775.5532382	775.9585665	700.0717791	8538.000213
	03-Jan-20 03:00:00	776.8039877	777.3170031	700.6507399	8519.847347
	03-Jan-20 04:00:00	775.7423696	775.9296524	699.0430545	8515.986682
	03-Jan-20 05:00:00	775.9934054	775.9731181	699.2030603	8524.114696
	03-Jan-20 06:00:00	775.9672559	776.4975867	699.2334703	8537.405544
	03-Jan-20 07:00:00	776.0379465	776.1840386	698.8107952	8512.599013
	03-Jan-20 08:00:00	774.9563627	774.9810631	697.5084312	8561.659456
	03-Jan-20 09:00:00	776.0765969	776.8896405	699.0187701	8519.754294
	03-Jan-20 10:00:00	775.6909615	775.6842045	698.5395228	8548.332332
	03-Jan-20 11:00:00	775.8412579	775.7276963	698.3741086	8565.266
	03-Jan-20 12:00:00	776.7830829	776.7285198	700.1165093	8534.356958
	03-Jan-20 13:00:00	774.8011732	774.8080799	697.8259834	8541.091301
	03-Jan-20 14:00:00	777.282164	777.3663624	700.0079373	8516.702257
	03-Jan-20 15:00:00	776.6556739	776.876221	700.9591172	8513.266297
	03-Jan-20 16:00:00	775.7514446	775.8410407	700.3112093	8514.930992
	03-Jan-20 17:00:00	775.4579672	775.5888188	699.907792	8524.719338
	03-Jan-20 18:00:00	776.0458885	775.8666289	701.3356381	8488.568277
	03-Jan-20 19:00:00	776.9137195	777.1382819	701.3803128	8511.800643
	03-Jan-20 20:00:00	775.5595064	775.7515479	699.9602852	8534.101804
	03-Jan-20 21:00:00	776.9527158	777.1736853	702.0488803	8496.634387
	03-Jan-20 22:00:00	774.8501402	775.3261292	699.4905206	8516.195754
	03-Jan-20 23:00:00	775.8816098	775.8565082	700.0780091	8515.719956
	04-Jan-20 00:00:00	776.9560232	777.0244899	701.4523989	8495.101769
	04-Jan-20 01:00:00	776.1755021	775.8845531	697.918364	8524.145516
	04-Jan-20 02:00:00	777.0136429	777.3818809	699.7287173	8518.208977
	04-Jan-20 03:00:00	776.9889743	776.6201613	699.4204686	8513.602825
	04-Jan-20 04:00:00	775.9079945	775.235515	698.3135258	8540.852584
	04-Jan-20 05:00:00	775.6204219	775.4743694	698.3095246	8534.933875
	04-Jan-20 06:00:00	777.3566517	777.425234	699.7354194	8527.476913
	04-Jan-20 07:00:00	776.4231472	776.3534241	698.7960209	8526.333124
	04-Jan-20 08:00:00	776.7021293	777.2510479	699.5594229	8520.65155
	04-Jan-20 09:00:00	776.7442898	776.3783237	699.1550506	8517.700393
	04-Jan-20 10:00:00	775.6519568	775.6701968	698.4884355	8531.987448
	04-Jan-20 11:00:00	775.9538665	776.1097923	699.7880663	8495.875104
	04-Jan-20 12:00:00	774.9919562	774.8667205	700.4697959	8494.723214
	04-Jan-20 13:00:00	774.265832	774.7614686	699.5081866	8523.294386

04-Jan-20 09:00:00	776.7442898	776.3783237	699.1550506	8517.700393
04-Jan-20 10:00:00	775.6519568	775.6701968	698.4884355	8531.987448
04-Jan-20 11:00:00	775.9538665	776.1097923	699.7880663	8495.875104
04-Jan-20 12:00:00	774.9919562	774.8667205	700.4697959	8494.723214
04-Jan-20 13:00:00	774.265832	774.7614686	699.5081866	8523.294386
04-Jan-20 14:00:00	776.262441	776.3688786	701.2326941	8494.447648
04-Jan-20 15:00:00	774.1797773	773.877328	699.3560181	8516.899837
04-Jan-20 16:00:00	774.8706845	775.0907826	700.2126269	8519.646873
04-Jan-20 17:00:00	774.7914425	774.8038132	699.8975079	8519.533152
04-Jan-20 18:00:00	773.9648309	774.4917343	699.4624388	8503.07632
04-Jan-20 19:00:00	774.1895309	773.7366831	698.9217634	8525.020817

LVP ACE Data 2020 Q1 Q2

Thursday, October 8, 2020 9:42 AM

LVP ACE Data 2020 Q1 Q2

Date/ Hour	BOILER01 CO2 Value	BOILER01 CO2T/ HR Value	BOILER01 FLOWSCFH Value	BOILER01 LOAD__MW Value	BOILER01 UNITOPHR Value
01/ 01/ 2020 00	12.1	661.5	95911500	773	60
01/ 01/ 2020 01	12.2	664.5	95559500	775	60
01/ 01/ 2020 02	12.2	665.4	95682300	773	60
01/ 01/ 2020 03	12.2	664.8	95598600	774	60
01/ 01/ 2020 04	12.1	660.1	95714400	774	60
01/ 01/ 2020 05	12.2	661.4	95105400	774	60
01/ 01/ 2020 06	12.2	663.4	95391900	774	60
01/ 01/ 2020 07	12.2	662.7	95295346.2	775	60
01/ 01/ 2020 08	12.2	661.7	95154600	772	60
01/ 01/ 2020 09	12.2	658.8	94740000	762	60
01/ 01/ 2020 10	12.2	660.9	95043300	775	60
01/ 01/ 2020 11	12.2	660.4	94961600	773	60
01/ 01/ 2020 12	12.2	649.3	93376100	756	60
01/ 01/ 2020 13	12.1	635.5	92135100	732	60
01/ 01/ 2020 14	12.1	619.2	89783900	712	60
01/ 01/ 2020 15	12	595.6	87081400	681	60
01/ 01/ 2020 16	12.1	634.7	92021900	725	60
01/ 01/ 2020 17	12.2	666.6	95857400	774	60
01/ 01/ 2020 18	12.2	668.8	96177000	775	60
01/ 01/ 2020 19	12.2	667.6	96007600	774	60
01/ 01/ 2020 20	12.2	667.6	96005400	775	60
01/ 01/ 2020 21	12.2	667.1	95936700	775	60
01/ 01/ 2020 22	12.2	667.2	95938300	775	60
01/ 01/ 2020 23	12.2	668.3	96104900	775	60
01/ 02/ 2020 00	12.2	668.9	96196400	775	60
01/ 02/ 2020 01	12.3	670.4	95615900	776	60
01/ 02/ 2020 02	12.3	670.1	95581800	775	60
01/ 02/ 2020 03	12.3	669.3	95459800	774	60
01/ 02/ 2020 04	12.2	666.9	95901300	775	60
01/ 02/ 2020 05	12.3	671.6	95794800	775	60
01/ 02/ 2020 06	12.3	670.4	95622000	774	60
01/ 02/ 2020 07	12.2	665.4	95686961.5	775	60
01/ 02/ 2020 08	12.3	670.1	95581000	773	60
01/ 02/ 2020 09	12.3	670.4	95626400	776	60
01/ 02/ 2020 10	12.3	666.5	95061400	776	60
01/ 02/ 2020 11	12.3	667.8	95254600	776	60
01/ 02/ 2020 12	12.2	661.7	95150200	776	60
01/ 02/ 2020 13	12.2	661.7	95147000	777	60
01/ 02/ 2020 14	12.2	657.7	94576200	777	60
01/ 02/ 2020 15	12.2	661.4	95109800	777	60
01/ 02/ 2020 16	12.2	664.6	95575932.2	775	59
01/ 02/ 2020 17	12.1	661.6	95926000	776	60
01/ 02/ 2020 18	12.1	659.2	95579300	776	60
01/ 02/ 2020 19	12.2	663.4	95402400	776	60
01/ 02/ 2020 20	12.2	662.3	95237000	777	60
01/ 02/ 2020 21	12.2	663.5	95413400	775	60
01/ 02/ 2020 22	12.1	666.4	96621500	776	60
01/ 02/ 2020 23	12.1	666.9	96699800	778	60
01/ 03/ 2020 00	12.1	663.3	96166300	776	60
01/ 03/ 2020 01	12.1	664.9	96396700	777	60
01/ 03/ 2020 02	12.1	663.3	96170600	776	60
01/ 03/ 2020 03	12.1	664	96277400	777	60
01/ 03/ 2020 04	12.1	660.3	95744100	776	60
01/ 03/ 2020 05	12.2	665.7	95725400	776	60
01/ 03/ 2020 06	12.2	664.6	95573400	776	60

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
01/03/2020 04	12.1	660.3	95744100	776	60
01/03/2020 05	12.2	665.7	95725400	776	60
01/03/2020 06	12.2	664.6	95573400	776	60
01/03/2020 07	12.2	665.7	95735307.7	777	60
01/03/2020 08	12.2	665.3	95676600	775	60
01/03/2020 09	12.2	665.5	95703200	777	60
01/03/2020 10	12.2	665.7	95736400	776	60
01/03/2020 11	12.2	668.2	96083700	776	60
01/03/2020 12	12.2	665.9	95756900	777	60
01/03/2020 13	12.2	667.4	95977300	775	60
01/03/2020 14	12.2	668.6	96140100	778	60
01/03/2020 15	12.2	669.4	96255300	777	60
01/03/2020 16	12.2	667.5	95992500	776	60
01/03/2020 17	12.2	667.5	95985900	776	60
01/03/2020 18	12.2	669.1	96214800	777	60
01/03/2020 19	12.2	670.1	96367200	777	60
01/03/2020 20	12.2	670.3	96391000	776	60
01/03/2020 21	12.2	667.1	95927300	777	60
01/03/2020 22	12.2	669.3	96252200	775	60
01/03/2020 23	12.1	666.4	96622000	776	60
01/04/2020 00	12.2	668.9	96183800	777	60
01/04/2020 01	12.2	668.3	96109800	777	60
01/04/2020 02	12.2	666.6	95859600	777	60
01/04/2020 03	12.2	669.2	96229600	777	60
01/04/2020 04	12.2	669.4	96261600	776	60
01/04/2020 05	12.2	669.5	96273700	776	60
01/04/2020 06	12.2	669.7	96297800	778	60
01/04/2020 07	12.2	667.1	95930538.5	777	60
01/04/2020 08	12.2	668.1	96073900	777	60
01/04/2020 09	12.2	669.6	96284300	777	60
01/04/2020 10	12.2	669.7	96308400	776	60
01/04/2020 11	12.2	665.6	95720100	776	60
01/04/2020 12	12.2	665.2	95650400	775	60
01/04/2020 13	12.2	670	96346800	775	60
01/04/2020 14	12.2	669.1	96216800	777	60
01/04/2020 15	12.2	667.9	96048500	775	60
01/04/2020 16	12.2	665	95632500	775	60
01/04/2020 17	12.2	669.6	96288900	775	60
01/04/2020 18	12.2	667.6	95998500	774	60
01/04/2020 19	12.2	668.6	96139400	775	60
01/04/2020 20	12.2	668.6	96149600	774	60
01/04/2020 21	12.2	668.3	96106100	774	60

LVP Degradation Table 2020-09-10

Thursday, October 8, 2020 9:42 AM

LVP Degradation Table 2020-09-10

Longview Power CO_2 Rate Degradation Table

Starting Year	**2021**	
Degradation	**0.4%**	annually
Recovery	**0.7%**	per 5 years

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Degradation	**0.0%**	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Recovery	**0.0%**	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHG)

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Bin															
0	**9,864**	9,903	9,943	9,983	9,953	9,992	10,032	10,073	10,113	10,082	10,123	10,163	10,204	10,244	10,213

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Bin															
1	**2,230**	2,239	2,248	2,257	2,250	2,259	2,268	2,277	2,286	2,279	2,288	2,298	2,307	2,316	2,309
2	**2,108**	2,116	2,125	2,133	2,127	2,135	2,144	2,153	2,161	2,155	2,163	2,172	2,181	2,189	2,183
3	**2,050**	2,058	2,066	2,075	2,068	2,077	2,085	2,093	2,102	2,095	2,104	2,112	2,121	2,129	2,123
4	**2,002**	2,010	2,018	2,026	2,020	2,028	2,036	2,044	2,052	2,046	2,054	2,063	2,071	2,079	2,073
5	**1,958**	1,966	1,974	1,982	1,976	1,983	1,991	1,999	2,007	2,001	2,009	2,017	2,025	2,034	2,027

Level 2 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Bin															
1	**2,453**	2,463	2,473	2,483	2,475	2,485	2,495	2,505	2,515	2,507	2,517	2,527	2,537	2,548	2,540
2	**2,319**	2,328	2,337	2,347	2,340	2,349	2,358	2,368	2,377	2,370	2,380	2,389	2,399	2,408	2,401
3	**2,255**	2,264	2,273	2,282	2,275	2,284	2,293	2,303	2,312	2,305	2,314	2,323	2,333	2,342	2,335
4	**2,202**	2,211	2,220	2,229	2,222	2,231	2,240	2,249	2,258	2,251	2,260	2,269	2,278	2,287	2,280
5	**2,154**	2,162	2,171	2,180	2,173	2,182	2,191	2,199	2,208	2,201	2,210	2,219	2,228	2,237	2,230

LVP Generation and OPM Heat Rates 2020-06-26

Thursday, October 8, 2020 9:43 AM

LVP Generation and OPM Heat Rates 2020-06-26

Longview Power Generation and OPM Heat Rate

As of 6/26/2020

	PI Tag 10MKA01CE903.XQ02	PI Tag 10CFE00CJ010.ZJ01		PI Tag CALRevMeterB		PI Tag 1OPM.CONLOSS:NETPLANTHR_HL
Time Period	Gross Generation 1 (MW)	Gross Generation 2 (MW)	Average Gross Gen (MW)	Net Generation (MW)	Net to Gross Ratio	OPM Heat Rate (Btu/KWh, HHV)
01-Jan-14 00:00:00						
01-Jan-14 01:00:00						
01-Jan-14 02:00:00						
01-Jan-14 03:00:00						
01-Jan-14 04:00:00						
01-Jan-14 05:00:00						
01-Jan-14 06:00:00						
01-Jan-14 07:00:00						
01-Jan-14 08:00:00						
01-Jan-14 09:00:00						
01-Jan-14 10:00:00						
01-Jan-14 11:00:00						
01-Jan-14 12:00:00						
01-Jan-14 13:00:00						
01-Jan-14 14:00:00						
01-Jan-14 15:00:00						
01-Jan-14 16:00:00						
01-Jan-14 17:00:00						
01-Jan-14 18:00:00						
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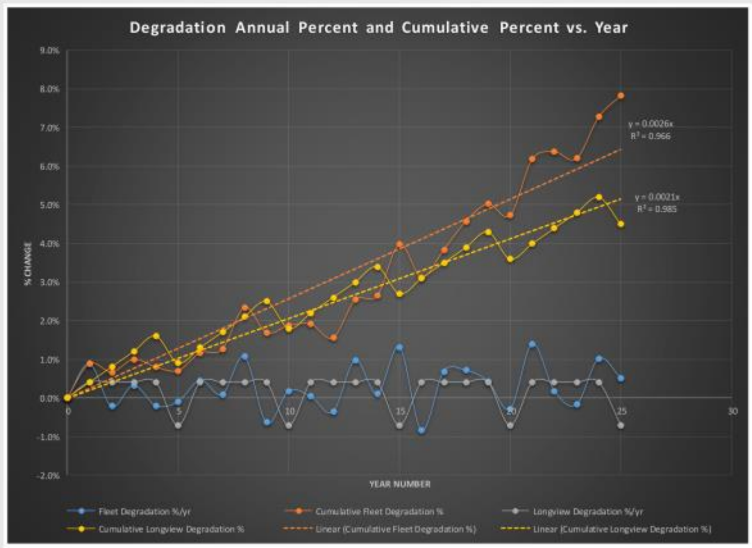
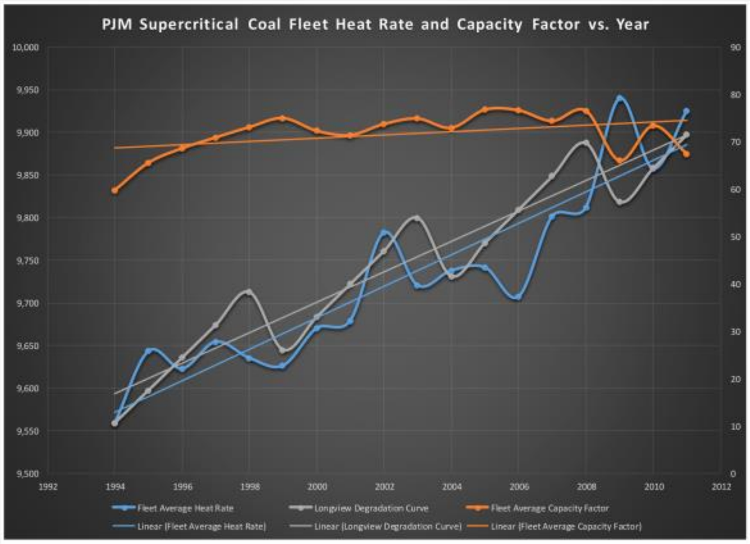
PJM Supercritical Coal Fleet Heat Rate and Capacity Factor Degradation R1

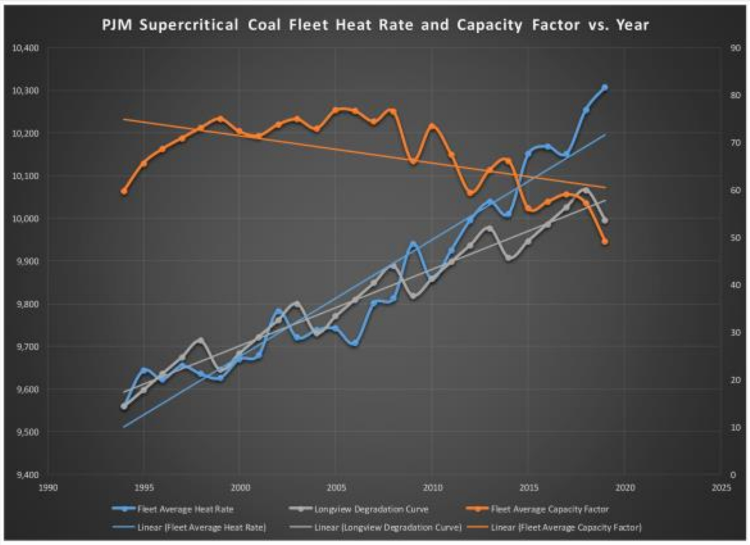
Thursday, October 8, 2020 9:44 AM

PJM Supercritical Coal Fleet Heat Rate and Capacity Facto...



Power Plant	Plant Key	Heat Rate 2019 Y (Btu/kWh)	Heat Rate 2018 Y (Btu/kWh)	Heat Rate 2017 Y (Btu/kWh)	Heat Rate 2016 Y (Btu/kWh)	Heat Rate 2015 Y (Btu/kWh)	Heat Rate 2014 Y (Btu/kWh)	Heat Rate 2013 Y (Btu/kWh)	Heat Rate 2012 Y (Btu/kWh)	Heat Rate 2011 Y (Btu/kWh)	Heat Rate 2010 Y (Btu/kWh)	Heat Rate 2009 Y (Btu/kWh)	Heat Rate 2008 Y (Btu/kWh)
221663	231679	225592	225592	225592	225592	225592	225592	225592	225592	225592	225592	225592	225592
		2019 Y	2018 Y	2017 Y	2016 Y	2015 Y	2014 Y	2013 Y	2012 Y	2011 Y	2010 Y	2009 Y	2008 Y
Cardinal	2139	9,916	10,018	10,005	9,936	9,893	9,967	10,069	9,993	10,088	9,912	9,900	9,781
Chalk Point 1 and 2	7595	11,874	11,687	12,377	10,861	10,803	10,871	10,691	10,505	9,988	9,793	10,098	10,246
Conemaugh	2477	9,601	9,594	9,691	9,916	9,766	9,785	9,658	9,737	9,787	9,648	9,534	9,482
Fort Martin	3172	10,352	10,414	10,155	10,204	10,211	10,243	10,041	10,000	10,193	10,315	10,338	9,945
Gen J M Gavin	3304	9,994	9,860	9,801	9,925	9,904	9,974	10,131	9,903	9,750	9,889	9,721	9,761
Gibson	3338	11,041	10,761	10,318	10,419	10,491	10,456	10,359	10,298	10,306	10,227	10,208	10,139
Harrison	3586	10,135	10,008	10,064	10,179	10,428	10,060	9,901	10,045	10,020	10,004	10,124	9,957
John E. Amos	4004	9,936	10,035	9,833	9,966	10,053	9,859	10,027	9,803	9,809	9,792	10,673	9,764
Keystone	4138	9,754	9,659	9,740	10,185	9,928	9,638	9,464	9,630	9,581	9,551	9,590	9,553
Mitchell (WV)	4824	10,713	10,800	9,968	10,144	10,084	9,770	10,035	10,029	9,828	9,756	9,811	9,848
Morgantown	4909	10,618	10,529	10,425	10,258	10,212	9,983	10,291	9,867	9,639	9,515	9,487	9,346
Mountaineer	4937	9,984	10,147	9,784	10,013	10,005	9,737	9,905	9,972	9,696	9,792	9,720	9,620
Pleasants	5588	10,762	10,560	10,314	10,462	10,601	10,292	10,403	10,306	10,122	10,122	10,177	10,073
Rockport	5967	10,284	10,095	9,948	10,223	10,113	9,803	9,867	9,772	9,769	9,678	9,743	9,704
W.H. Zimmer	7079	9,651	9,653	9,852	9,834	9,763	9,726	9,742	10,080	10,305	9,870	9,976	9,959
		2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Fleet Average Heat Rate		10,308	10,255	10,152	10,168	10,150	10,011	10,039	9,996	9,925	9,858	9,940	9,812
Fleet Average Capacity Factor		49	57	59	57	56	66	64	59	67	73	66	77
Longview Degradation Curve		9995.893074	10066.35758	10026.25257	9986.307338	9946.521253	9906.893678	9976.730794	9936.982862	9897.393289	9857.961443	9818.686697	9887.902011
Percent Change Analysis													
Year		25	24	23	22	21	20	19	18	17	16	15	14
Fleet Degradation %/yr		0.517%	1.015%	-0.164%	0.177%	1.392%	-0.279%	0.430%	0.711%	0.688%	-0.829%	1.306%	0.104%
Cumulative Fleet Degradation %		7.835%	7.280%	6.203%	6.377%	6.189%	4.731%	5.023%	4.574%	3.836%	3.126%	3.988%	2.648%
Longview Degradation %/yr		-0.70%	0.40%	0.40%	0.40%	0.40%	-0.70%	0.40%	0.40%	0.40%	0.40%	-0.70%	0.40%
Cumulative Longview Degradation %		4.500%	5.200%	4.800%	4.400%	4.000%	3.600%	4.300%	3.900%	3.500%	3.100%	2.700%	3.400%
Source:													
S&P Market Intelligence													
Operating Status	Operating												
Ownership Level	Whole Plant Records												
Plant Location	PJM												
Fuel Group	Coal												
Technology Type	Steam Turbine												
Additional Filters													
100% Supercritical Plants													
Eliminated new units - Longview and Praire State													


PJM Supercritical Coal Fleet Heat Rate and Capacity Factor vs. Year
Fleet Average Heat Rate
Longview Degradation Curve
Fleet Average Capacity Factor
Linear (Fleet Average Heat Rate)
Linear (Longview Degradation Curve)
Linear (Fleet Average Capacity Factor)


PJM Supercritical Coal Fleet Heat Rate and Capacity Factor vs. Year
Fleet Average Heat Rate
Longview Degradation Curve
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Linear (Longview Degradation Curve)
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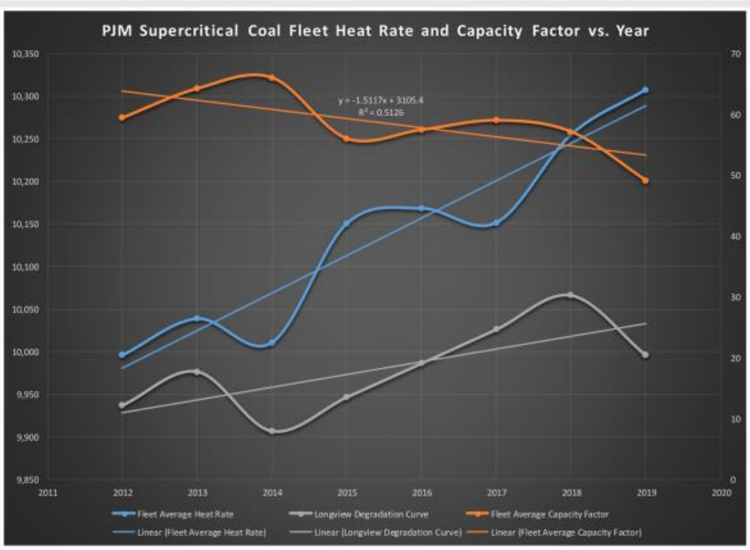
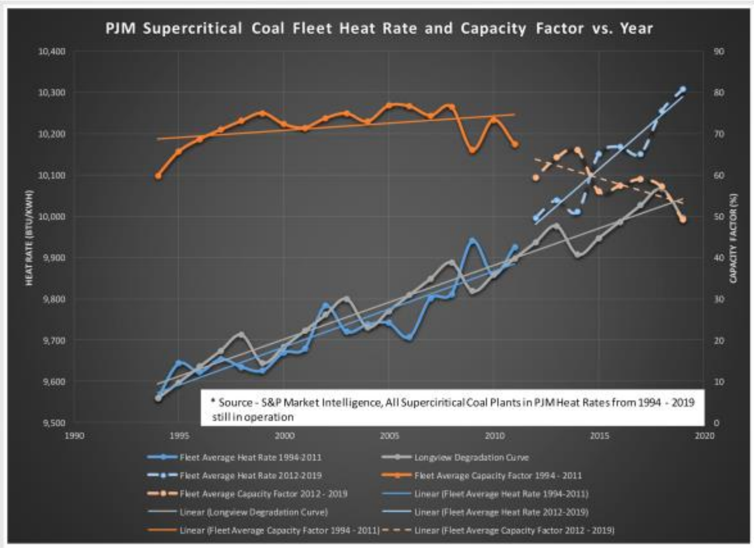

PJM Supercritical Coal Fleet Heat Rate and Capacity Factor vs. Year
y = -1.5117x + 3105.4
R² = 0.5126
Fleet Average Heat Rate
Longview Degradation Curve
Fleet Average Capacity Factor
Linear (Fleet Average Heat Rate)
Linear (Longview Degradation Curve)
Linear (Fleet Average Capacity Factor)


PJM Supercritical Coal Fleet Heat Rate and Capacity Factor vs. Year
HEAT RATE (BTU/KWH)
CAPACITY FACTOR (%)
10,400
10,300
10,200
10,100
10,000
9,900
9,800
9,700
9,600
9,500
90
80
70
60
50
40
30
20
10
0
1990
1995
2000
2005
2010
2015
2020
* Source - S&P Market Intelligence, All Superciritical Coal Plants in PJM Heat Rates from 1994 - 2019 still in operation
Fleet Average Heat Rate 1994-2011
Longview Degradation Curve
Fleet Average Heat Rate 2012-2019
Fleet Average Capacity Factor 1994 - 2011
Fleet Average Capacity Factor 2012 - 2019
Linear (Fleet Average Heat Rate 1994-2011)
Linear (Longview Degradation Curve)
Linear (Fleet Average Heat Rate 2012-2019)
Linear (Fleet Average Capacity Factor 1994 - 2011)
Linear (Fleet Average Capacity Factor 2012 - 2019)

LVP ACE Rule Load Bin Compliance Analysis Tool Snapshot
2020-07-24

Thursday, October 8, 2020 9:46 AM

LVP ACE Rule Load Bin Compliance Analysis Tool Snapshot ...

Longview Power ACE Rule Compliance Calculation Worksheet

CO_2 Limit Determination - Baseline

Load Bin	Bin Range	Level 1	Time	Time	Level 2	Time	Time
		lbs/MWHN	hours	%	lbs/MWHN	hours	%
0	< 313 MWG	9,973					
1	313-407 MWG	2,479	43	1%	2,727	-	0%
2	407-501 MWG	2,213	416	12%	2,434	-	0%
3	501-595 MWG	2,136	330	9%	2,350	-	0%
4	595-689 MWG	2,050	341	10%	2,255	-	0%
5	689-783 MWG	1,978	2,426	68%	2,176	-	0%
	Total	2,033	3,556		-	-	

Total (L1 & L2)	3,556	hours	Overall	2,033	lbs / MWHN
Level 2 Modifier	10%		CO_2	2,033	lbs / MWHN

Bin 0 Compliance Calculation

Total Bin 0 Gross Generation	1,531	MWHG/yr
Total Bin 0 CO_2 Emissions	7,470,200	lbs/yr
Annual Performance Standard	9,973	lbs/MWHG
Calculated Performance	4,879	lbs/MWHG
Compliance Margin	51.07%	

Bins 1-5 Compliance Calculation

Total Bin 1-5 Net Generation	2,234,828	MWHN/yr
Total Bin 1-5 CO_2 Emissions	4,322,822,000	lbs/yr
Annual Performance Standard	2,033	lbs/MWHN
Calculated Performance	1,934	lbs/MWHN
Compliance Margin	4.86%	

Calculation Methods & Overall Methodology

Enter data in green cells/ blue txt

Bin 0	TBD
Bin 1	L1 = 2016 - 2020-Q2 98th % Confidence of Hourly Rates, L2 = 110%*L1
Bin 2	L1 = 2016 - 2020-Q2 98th % Confidence of Hourly Rates, L2 = 110%*L1
Bin 3	L1 = 2016 - 2020-Q2 98th % Confidence of Hourly Rates, L2 = 110%*L1
Bin 4	L1 = 2016 - 2020-Q2 98th % Confidence of Hourly Rates, L2 = 110%*L1
Bin 5	L1 = 2016 - 2020-Q2 98th % Confidence of Hourly Rates, L2 = 110%*L1
Bin 0 - SUSD	Independent Limit, calculation based only on SUSD data, use Gross not Net, broad sums and division to negate "zero" issue
Level 1	Normal Operation of the Unit, final tbd
Level 2	Event occurs, declare Level 2 limit in effect, provide documentation to WVDEP DAQ to justify, 110% L1 limits
Emergency Event	TBD
Compliance	Calculate Bin 0 compliance, Sum of CO2 lbs / Sum of MWHN for loads < 313 MWG
	Subtract Bin 0 hours from Bin (L1 1-5 + L2 1-5) hours
	Remove all CO2 lbs and MWHN @ < 313 MWG annual Sums
	Calculate time spent in each of 10 bins and create TWA compliance standard for calendar year
	Determine compliance, actual versus target, for Bin 0 and L1/L2 Bins 1-5
Degredation	Degredation applied from Year 1 and beyond, Level 2 calculated based on L1 degredation per year
	*To be added

Longview Power CO_2 Standard Degradation Table

Starting Year	2021	
Degredation	0.4%	annually
Recovery	0.7%	per 5 years

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Degradation	0.0%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Bin																
1	2,479	2,489	2,499	2,509	2,519	2,511	2,521	2,531	2,542	2,552	2,544	2,554	2,564	2,575	2,585	2,577
2	2,213	2,222	2,231	2,240	2,249	2,242	2,251	2,260	2,269	2,278	2,271	2,280	2,289	2,298	2,308	2,301
3	2,136	2,145	2,153	2,162	2,170	2,164	2,172	2,181	2,190	2,199	2,192	2,201	2,210	2,218	2,227	2,221
4	2,050	2,058	2,066	2,075	2,083	2,077	2,085	2,093	2,102	2,110	2,104	2,112	2,121	2,129	2,138	2,131
5	1,978	1,986	1,994	2,002	2,010	2,004	2,012	2,020	2,028	2,036	2,030	2,038	2,046	2,054	2,063	2,056

Level 2 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Bin																
1	2,727	2,738	2,749	2,760	2,771	2,762	2,773	2,785	2,796	2,807	2,798	2,810	2,821	2,832	2,843	2,835
2	2,434	2,444	2,454	2,464	2,473	2,466	2,476	2,486	2,496	2,506	2,498	2,508	2,518	2,528	2,538	2,531
3	2,350	2,359	2,368	2,378	2,387	2,380	2,390	2,399	2,409	2,419	2,411	2,421	2,431	2,440	2,450	2,443
4	2,255	2,264	2,273	2,282	2,291	2,284	2,293	2,303	2,312	2,321	2,314	2,323	2,333	2,342	2,351	2,344
5	2,176	2,185	2,193	2,202	2,211	2,204	2,213	2,222	2,231	2,240	2,233	2,242	2,251	2,260	2,269	2,262

Longview Power Potential Bin CO_2 Compliance Standards

Type	Calculation	Abbreviation	Load Bin 1	Load Bin 2	Load Bin 3	Load Bin 4	Load Bin 5
			lb/MWHN	lb/MWHN	lb/MWHN	lb/MWHN	lb/MWHN
Monthly Avg	Straight	MA-Straight	2,181	2,052	2,004	1,968	1,916
Monthly Avg	98th of the Monthly Avg	MA-98th of the Monthly Avg	2,533	2,188	2,096	2,047	1,966
Monthly Avg	95th of the Monthly Avg	MA-95th of the Monthly Avg	2,331	2,168	2,073	2,032	1,960
Monthly Avg	Avg + 1 SD	MA-Avg + 1 SD	2,330	2,133	2,070	2,009	1,947
Monthly Avg	Avg + 1.5 SD	MA-Avg + 1.5 SD	2,405	2,173	2,103	2,030	1,962
Monthly Avg	Avg +2 SD	MA-Avg +2 SD	2,479	2,213	2,136	2,050	1,978
12-Month Rolling	98th	MR-98th	2,224	2,095	2,032	1,996	1,941
12-Month Rolling	Avg + 5%	MR-Avg + 5%	2,288	2,151	2,098	2,063	2,012
Variable	98th 18 M for LB-1 & LB-2; 98th 12M for LB-3 through LB-5	Var-01	2,213	2,095	2,032	1,996	1,941
		Var-02	2,178	2,095	2,032	1,996	1,941
Qtr Avg	Average	QA-Average	2,175	2,057	2,005	1,964	1,917
Qtr Avg	98th of the Qtr Avg	QA-98th of the Qtr Avg	2,292	2,141	2,075	2,019	1,951
Qtr Avg	Avg + 1 SD	QA-Avg + 1 SD	2,241	2,112	2,052	1,995	1,942
Qtr Avg	Avg + 1.5 SD	QA-Avg + 1.5 SD	2,275	2,140	2,075	2,011	1,955
Qtr Avg	Avg + 2 SD	QA-Avg + 2 SD	2,308	2,168	2,098	2,027	1,968

Notes
Based on WVDEP DAQ numbers shared on 2020-07-23

LONGVIEW POWER LLC

A New Generation of Power

RECEIVED
JUN 01 2020
WV DEP / DIV OF AIR QUALITY

June 1, 2020

Ms. Laura Crowder, Director
WVDEP - Division of Air Quality
601 57th Street
Charleston, WV 25304

Re: Request for Administrative Amendment
Permits R14-0024G and R30-06100134-2018
Longview Power Plant
DAQ Facility ID 0061-00134
Maidsville, Monongalia County, WV

Dear Ms. Crowder:

This letter follows the recent conversations regarding the WVDEP implementation of 40 CFR Part 60, subpart UUUUa, commonly referred to as the Affordable Clean Energy (ACE) Rule, 40 CFR Part 60, subpart Ba, and subsequent development of 45CSR44. In response to the promulgation of these rules, Longview Power is requesting an amendment to existing permits R14-0024G and R30-06100134-2018 to include the Carbon Dioxide (CO2) Standard of Performance, and associated program requirements. Attached please find the support documentation for this request.

If you have any questions, please contact me, at (304) 282-5059 or snelson@longviewpower.net.

Sincerely,

Stephen Nelson
Chief Operating Officer – Longview Power, LLC

cc:

Secretary Austin Caperton	WV Department of Environmental Protection
Scott Mandirola, Deputy Secretary	WV Department of Environmental Protection
Edward Andrews, Engineer	WV Department of Environmental Protection
Anne Idsal, Principal Deputy Asst.	USEPA Headquarters Administrator
Karl Moore, Deputy Chief Administrator	USEPA Headquarters
Cosmo Servidio, Regional Administrator	Environmental Protection Agency, Region 3
Brian Abraham, General Counsel	Office of the Governor, West Virginia
Thomas Lampman, Assist. Solicitor	Office of the WV Attorney General

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION **DIVISION OF AIR QUALITY** 601 57th Street, SE Charleston, WV 25304 (304) 926-0475 www.dep.wv.gov/daq	***APPLICATION FOR NSR PERMIT*** ***AND*** ***TITLE V PERMIT REVISION*** ***(OPTIONAL)***
PLEASE CHECK ALL THAT APPLY TO **NSR (45CSR13)** (IF KNOWN): ☐ **CONSTRUCTION** ☐ **MODIFICATION** ☐ **RELOCATION** ☐ **CLASS I ADMINISTRATIVE UPDATE** ☐ **TEMPORARY** ☐ **CLASS II ADMINISTRATIVE UPDATE** ☐ **AFTER-THE-FACT**	PLEASE CHECK TYPE OF **45CSR30 (TITLE V)** REVISION (IF ANY): ☐ **ADMINISTRATIVE AMENDMENT** ☐ **MINOR MODIFICATION** ☐ **SIGNIFICANT MODIFICATION** IF ANY BOX ABOVE IS CHECKED, INCLUDE TITLE V REVISION INFORMATION AS **ATTACHMENT S** TO THIS APPLICATION

FOR TITLE V FACILITIES ONLY: Please refer to "Title V Revision Guidance" in order to determine your Title V Revision options (Appendix A, "Title V Permit Revision Flowchart") and ability to operate with the changes requested in this Permit Application.

Section I. General

1. Name of applicant *(as registered with the WV Secretary of State's Office):* *Longview Power, LLC*	2. Federal Employer ID No. ***(FEIN):*** *04-3561860*
3. Name of facility *(if different from above):*	4. The applicant is the: ☐ **OWNER** ☐ **OPERATOR** ☒ **BOTH**
5A. Applicant's mailing address: 1375 Fort Martin Rd. Maidsville, WV 26541	5B. Facility's present physical address: 1375 Fort Martin Rd. Maidsville, WV 26541

6. **West Virginia Business Registration.** Is the applicant a resident of the State of West Virginia? ☐ **YES** ☒ **NO**
- If **YES,** provide a copy of the **Certificate of Incorporation/Organization/Limited Partnership** (one page) including any name change amendments or other Business Registration Certificate as **Attachment A.**
- If **NO,** provide a copy of the **Certificate of Authority/Authority of L.L.C./Registration** (one page) including any name change amendments or other Business Certificate as **Attachment A.**

7. If applicant is a subsidiary corporation, please provide the name of parent corporation:

8. Does the applicant own, lease, have an option to buy or otherwise have control of the *proposed site?* ☒ **YES** ☐ **NO**
- If **YES,** please explain: *Existing facility*
- If **NO,** you are not eligible for a permit for this source.

9. Type of plant or facility (stationary source) to be **constructed, modified, relocated, administratively updated** or **temporarily permitted** (e.g., coal preparation plant, primary crusher, etc.): *Coal-Fired EGU*	10. North American Industry Classification System **(NAICS)** code for the facility: *221112*
11A. DAQ Plant ID No. (for existing facilities only): *0061--00134*	11B. List all current 45CSR13 and 45CSR30 (Title V) permit numbers associated with this process (for existing facilities only): *R14-0024G, R30-06100134-2018, R33-56671-2023-3*

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

12A. — For **Modifications, Administrative Updates** or **Temporary permits** at an existing facility, please provide directions to the *present location* of the facility from the nearest state road; — For **Construction** or **Relocation permits**, please provide directions to the *proposed new site location* from the nearest state road. Include a **MAP** as **Attachment B**. *Longview Power facility is located on SR53, Fort Martin Rd. Physical address is 1375 Fort Martin Rd, Maidsville, WV 26541.*

12.B. New site address (if applicable): *N/A*	12C. Nearest city or town:	12D. County:
12.E. UTM Northing (KM):	12F. UTM Easting (KM):	12G. UTM Zone:

13. Briefly describe the proposed change(s) at the facility: *Incorporation of 40 CFR Part 60, subpart UUUUa, and 45CSR44, ACE Rule Carbon Dioxide Standard of Performance into State (R14-0024G) and Federal (R30-06100134-2018) air permits.*	
14A. Provide the date of anticipated installation or change: *N/A* / / — If this is an **After-The-Fact** permit application, provide the date upon which the proposed change did happen: / /	14B. Date of anticipated Start-Up if a permit is granted: / /
14C. Provide a **Schedule** of the planned **Installation** of/**Change** to and **Start-Up** of each of the units proposed in this permit application as **Attachment C** (if more than one unit is involved). *N/A*	
15. Provide maximum projected **Operating Schedule** of activity/activities outlined in this application: ***24*** Hours Per Day ***7*** Days Per Week ***52*** Weeks Per Year	
16. Is demolition or physical renovation at an existing facility involved? ☐ **YES** ☒ **NO**	
17. **Risk Management Plans.** If this facility is subject to 112(r) of the 1990 CAAA, or will become subject due to proposed changes (for applicability help see www.epa.gov/ceppo), submit your **Risk Management Plan (RMP)** to U. S. EPA Region III.	
18. **Regulatory Discussion.** List all Federal and State air pollution control regulations that you believe are applicable to the proposed process *(if known)*. A list of possible applicable requirements is also included in Attachment S of this application (Title V Permit Revision Information). Discuss applicability and proposed demonstration(s) of compliance *(if known)*. Provide this information as **Attachment D.** ***Please see Attachment LVP-1***	

Section II. Additional attachments and supporting documents.

19. Include a check payable to WVDEP – Division of Air Quality with the appropriate **application fee** (per 45CSR22 and 45CSR13).
20. Include a **Table of Contents** as the first page of your application package. *N/A*
21. Provide a **Plot Plan**, e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is or is to be located as **Attachment E** (Refer to ***Plot Plan Guidance***). *N/A* - Indicate the location of the nearest occupied structure (e.g. church, school, business, residence).
22. Provide a **Detailed Process Flow Diagram(s)** showing each proposed or modified emissions unit, emission point and control device as **Attachment F.** *N/A*
23. Provide a **Process Description** as **Attachment G.** *N/A* – Also describe and quantify to the extent possible all changes made to the facility since the last permit review (if applicable).
All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

24. Provide **Material Safety Data Sheets (MSDS)** for all materials processed, used or produced as **Attachment H.**
- For chemical processes, provide a MSDS for each compound emitted to the air. *N/A*

25. Fill out the **Emission Units Table** and provide it as **Attachment I.** *N/A*

26. Fill out the **Emission Points Data Summary Sheet (Table 1 and Table 2)** and provide it as **Attachment J.** *N/A*

27. Fill out the **Fugitive Emissions Data Summary Sheet** and provide it as **Attachment K.** *N/A*

28. Check all applicable **Emissions Unit Data Sheets** listed below: *N/A*

☐ Bulk Liquid Transfer Operations
☐ Chemical Processes
☐ Concrete Batch Plant
☐ Grey Iron and Steel Foundry
☐ General Emission Unit, specify
☐ Haul Road Emissions
☐ Hot Mix Asphalt Plant
☐ Incinerator
☐ Indirect Heat Exchanger
☐ Quarry
☐ Solid Materials Sizing, Handling and Storage Facilities
☐ Storage Tanks

Fill out and provide the **Emissions Unit Data Sheet(s)** as **Attachment L.**

29. Check all applicable **Air Pollution Control Device Sheets** listed below: *N/A*

☐ Absorption Systems
☐ Adsorption Systems
☐ Afterburner
☐ Baghouse
☐ Condenser
☐ Electrostatic Precipitator
☐ Flare
☐ Mechanical Collector
☐ Wet Collecting System

☐ Other Collectors, specify

Fill out and provide the **Air Pollution Control Device Sheet(s)** as **Attachment M.**

30. Provide all **Supporting Emissions Calculations** as **Attachment N,** or attach the calculations directly to the forms listed in Items 28 through 31. *N/A*

31. **Monitoring, Recordkeeping, Reporting and Testing Plans.** Attach proposed monitoring, recordkeeping, reporting and testing plans in order to demonstrate compliance with the proposed emissions limits and operating parameters in this permit application. Provide this information as **Attachment O.** *N/A*

Y Please be aware that all permits must be practically enforceable whether or not the applicant chooses to propose such measures. Additionally, the DAQ may not be able to accept all measures proposed by the applicant. If none of these plans are proposed by the applicant, DAQ will develop such plans and include them in the permit.

32. **Public Notice.** At the time that the application is submitted, place a **Class I Legal Advertisement** in a newspaper of general circulation in the area where the source is or will be located (See 45CSR§13-8.3 through 45CSR§13-8.5 and ***Example Legal Advertisement*** for details). Please submit the **Affidavit of Publication** as **Attachment P** immediately upon receipt. *N/A*

33. **Business Confidentiality Claims.** Does this application include confidential information (per 45CSR31)?

☒ **YES** ☐ **NO**

Y If **YES,** identify each segment of information on each page that is submitted as confidential and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"Precautionary Notice – Claims of Confidentiality"*** guidance found in the ***General Instructions*** as **Attachment Q.** Attachment LVP-1

Section III. Certification of Information

34. **Authority/Delegation of Authority.** Only required when someone other than the responsible official signs the application. Check applicable **Authority Form** below:

☐ Authority of Corporation or Other Business Entity
☐ Authority of Governmental Agency
☐ Authority of Partnership
☐ Authority of Limited Partnership

Submit completed and signed **Authority Form** as **Attachment R.**

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

35A. **Certification of Information.** To certify this permit application, a Responsible Official (per 45CSR§13-2.22 and 45CSR§30-2.28) or Authorized Representative shall check the appropriate box and sign below.

Certification of Truth, Accuracy, and Completeness

I, the undersigned ☑ **Responsible Official** / ☐ **Authorized Representative,** hereby certify that all information contained in this application and any supporting documents appended hereto, is true, accurate, and complete based on information and belief after reasonable inquiry I further agree to assume responsibility for the construction, modification and/or relocation and operation of the stationary source described herein in accordance with this application and any amendments thereto, as well as the Department of Environmental Protection, Division of Air Quality permit issued in accordance with this application, along with all applicable rules and regulations of the West Virginia Division of Air Quality and W.Va. Code § 22-5-1 et seq. (State Air Pollution Control Act). If the business or agency changes its Responsible Official or Authorized Representative, the Director of the Division of Air Quality will be notified in writing within 30 days of the official change.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

SIGNATURE ______________________ *(Please use blue ink)* DATE: 5-22-2020 *(Please use blue ink)*

35B. Printed name of signee: STEPHON Nelson		35C. Title: COO
35D. E-mail: SNelson@Longviewpower.NET	36E. Phone: 304 282 5059	36F. FAX: 304-599 1673
36A. Printed name of contact person (if different from above):		36B. Title:
36C. E-mail:	36D. Phone:	36E. FAX:

PLEASE CHECK ALL APPLICABLE ATTACHMENTS INCLUDED WITH THIS PERMIT APPLICATION:

- ☐ **Attachment A: Business Certificate**
- ☐ **Attachment B: Map(s)**
- ☐ **Attachment C: Installation and Start Up Schedule**
- ☐ **Attachment D: Regulatory Discussion**
- ☐ **Attachment E: Plot Plan**
- ☐ **Attachment F: Detailed Process Flow Diagram(s)**
- ☐ **Attachment G: Process Description**
- ☐ **Attachment H: Material Safety Data Sheets (MSDS)**
- ☐ **Attachment I: Emission Units Table**
- ☐ **Attachment J: Emission Points Data Summary Sheet**
- ☐ **Attachment K: Fugitive Emissions Data Summary Sheet**
- ☐ **Attachment L: Emissions Unit Data Sheet(s)**
- ☐ **Attachment M: Air Pollution Control Device Sheet(s)**
- ☐ **Attachment N: Supporting Emissions Calculations**
- ☐ **Attachment O: Monitoring/Recordkeeping/Reporting/Testing Plans**
- ☐ **Attachment P: Public Notice**
- ☐ **Attachment Q: Business Confidential Claims**
- ☐ **Attachment R: Authority Forms**
- ☐ **Attachment S: Title V Permit Revision Information**
- ☐ **Application Fee**

Please mail an original and three (3) copies of the complete permit application with the signature(s) to the DAQ, Permitting Section, at the address listed on the first page of this application. Please DO NOT fax permit applications.

FOR AGENCY USE ONLY – IF THIS IS A TITLE V SOURCE:

- ☐ ***Forward 1 copy of the application to the Title V Permitting Group and:***
- ☐ ***For Title V Administrative Amendments:***
  - ☐ ***NSR permit writer should notify Title V permit writer of draft permit,***
- ☐ ***For Title V Minor Modifications:***
  - ☐ ***Title V permit writer should send appropriate notification to EPA and affected states within 5 days of receipt,***
  - ☐ ***NSR permit writer should notify Title V permit writer of draft permit.***
- ☐ ***For Title V Significant Modifications processed in parallel with NSR Permit revision:***
  - ☐ ***NSR permit writer should notify a Title V permit writer of draft permit,***
  - ☐ ***Public notice should reference both 45CSR13 and Title V permits,***
  - ☐ ***EPA has 45 day review period of a draft permit.***

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JUN 01 2020
WV DEP / DIV OF AIR QUALITY

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

Attachment LVP-1a

Per W. Va. C.S.R. § 45-44-4, "Permit application requirements," please see the following applicable conditions as they relate to the Longview Power EGU.

4.3. The owner or operator of a unit shall provide a heat rate improvement analysis and the associated degree of emission limitation achievable for each unit as specified in subdivisions 4.3.a and 4.3.b.

The Longview Power Heat Rate Improvement analysis (summarized in Table 1 below) is based on the EPA guidance of best available technology (BAT) and the potential heat rate improvements (HRI) based on a unit greater than 500 MW. In Longview's case, all of the technical equipment solutions are part of the base design of the facility except for Neural Network/Intelligent Combustion and Intelligent Sootblowing, which were integrated after the Commercial Operating Date (COD). Intelligent Sootblowing created benefits due to reduction in reheat spray flow and improved heat transfer. Intelligent Combustion with the Neural Network allowed for a reduction in O_2 in boiler resulting in a heat rate benefit.

Table 1 has an assumption of an 8,800 btu/kwh baseline to calculate the targeted range of potential improvement proposed in EPA's Affordable Clean Energy (ACE) rule. 84 FED. REG. 32,520 (July 8, 2019). Additional columns are added to list the Longview results for both the post COD improvements (highlighted in yellow) and the technologies inherent in the base facility design (highlighted in green).

Table 1 - Longview Power Heat Rate Improvement

HRI Measure	> 500 MW		Longview Target (Btu/KWh)		Longview Captured (Btu/KWh)		Longview Potential (Btu/KWh)	
(Assuming 8,800 Btu/kwh baseline OPM heat rate)	% Min	% Max	Min	Max	Low	High	Low	High
*DCS / Neural Network / Intelligent Sootblowers	0.3	0.9	26.4	79.2	45.0	90.0	-	-
**Boiler Feed Pumps	0.2	0.5	17.6	44.0	17.6	44.0	-	-
**Air Heater & Duct Leakage Control	0.1	0.4	8.8	35.2	8.8	35.2	-	-
**Variable Frequency Drives	0.2	1.0	17.6	88.0	17.6	88.0	-	-
**Blade Path Ugrade (Steam Turbine)	1.0	2.9	88.0	255.2	88.0	255.2	-	-
**Redesign / Replace Economizer	0.5	1.0	44.0	88.0	44.0	88.0	-	-
**Improved Operating and Maintenance (O & M) Practices	-	2.0	-	176.0	-	176.0		
*Measured HRI Improvements	2.3	8.7	202.4	765.6	221.0	776.4	-	-
**Assumed Captured Due to Full Unit Baseline Incorporation					109%	101.4%	0.0%	0.0%

As discussed in further detail below, Longview has considered each of the best system of emission reduction (BSER) technologies and practices specifically enumerated in the ACE rule. Longview has already fully implemented six of the seven BSER technologies and practices. The only identified exception is the possibility of variable frequency drives (VFD) on some facility equipment; however, the technology used instead of VFD is equivalent to or better than VFD. In the very limited instances in which VFD could be added and provide some HRI, i.e. on condensate pumps, the expected costs of $750,000 to $1,200,000 for such a project compared with expected trivial HRI of 1 – 3 btu/kwh benefit in return demonstrates they would not be cost effective projects and would take longer than the life of the facility for a return on investment. Thus, Longview has been unable to identify any further HRI required by the ACE rule.

EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. EPA expects this to be a part of many state plans." 84 FED. REG. at 32,554. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO_2 reductions." *Id.* at 32,553. Since Longview has already integrated the BSER technologies contemplated by the ACE rule (or in the case of VFDs an alternative providing even more HRI) into the design, construction and operation of the plant which have successfully achieved both high efficiency and low CO_2 emissions, and with any further trivial potential HRI not being cost effective, Longview is in compliance with the intent of the ACE rule without further HRI.

4.3.a. The permit application must include an applicability evaluation for each of the following heat rate improvements technologies identified in paragraphs 4.3.a.1 through 4.3.a.7 to each unit:

4.3.a.1. Neural Network and Intelligent Sootblowers:

Has this HRI been previously applied to the EGU?

Yes

What was the start-up date?

Neural Network DCS Upgrade / Replacement - June 2015
Intelligent Sootblowing - Fall 2015
Intelligent Combustion - Fall 2018

What HRI improvement was achieved?

The Distributed Control System (DCS) is a digital hardware/software process that takes a large number of operating data points across the plant's systems to control and adjust processes through a central control station. This initial upgrade enabled the inclusion of Intelligent Combustion and Intelligent Sootblowing in an efficient and cost effective manner.

Intelligent Combustion – Approximately 20 to 40 btu/kwh due to a 1% reduction in oxygen

Intelligent Sootblowing – Approximately 25 to 50 btu/kwh due to ability to control reheat spray and increase heat transfer in boiler

How much longer will the HRI be observed?

Sustained benefit for life of EGU with appropriate maintenance of systems

Are there further upgrades or improvements available with this technology?

No additional benefits identified. There is significant focus on daily activities to keep systems optimized for sustained benefit with fully staffed controls, reliability, and performance engineers and specialists.

4.3.a.2. Boiler Feed Pumps:

Has this HRI been previously applied to the EGU?

Yes, as part of base design. BFPs have a BAT Variable Speed Hydraulic Coupling to allow for efficient control and optimization of process.

What was the start-up date?

2011 original commissioning – Base Design of BFP is a leading design of efficiency.

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Pump performance will slowly degrade over time due to normal wear and tear. Longview has extensive condition and performance modeling programs, both in-house and via a third party, to insure pumps stay reliable and on pump curves to maintain efficiency over maintenance cycle of pumps. A pump rebuild is designed to take a pump back to near new performance so with proper maintenance the heat rate can be maintained.

Are there further upgrades or improvements available with this technology?

No. Current pump design and operation is consistent with BAT for new installations.

4.3.a.3. Air Heater and Duct Leakage Control:

Has this HRI been previously applied to the EGU?

Yes, as part of base design

What was the start-up date?

2011 original commissioning

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance. Air Heater distortion will occur over life of EGU which will degrade the sealing capability.

Are there further upgrades or improvements available with this technology?

No, technology applied is a BAT

4.3.a.4. Variable Frequency Drives:

Has this HRI been previously applied to the EGU?

Longview's design incorporates the use of variable pitch axial fans to control the input of air and exhaust of gases (balance draft unit). The intent of using VFDs is to provide increased efficiencies for older centrifugal fans commonly used on the bulk of the US's coal fleet. Longview due to its recent design makes use of the constant speed motive force but varies the pitch of the fan's blades to control flow. This results in greater efficiency for the motor in a manner that is equivalent to or better than the centrifugal fan/VFD format.[1] The use of variable pitch axial flow fans results in a 0.39% to 0.53% (full load benefit only) heat rate improvement over constant speed centrifugal fans while providing for better efficiency over a wider load range. Due to this, Longview does not expect that VFD would provide any additional HRI over the application of the axial flow fans currently installed.

What piece(s) of equipment (force-draft, induced-draft, pumps, etc.) have had VFDs installed?

Induced Draft Fans have Variable Blade Pitch Design
Forced Draft Fans have Variable Blade Pitch Design

What was the start-up date?

2011 original commissioning

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance

Are there further upgrades or improvements available with this technology?

Not with the air/fan systems - the axial variable blade pitch fan design is the current state of the art for power plant fan systems.

VFDs may provide some heat rate improvement in selected condensate pumps should the Longview unit face a significant change in its operating regime (i.e. increased low load cycling). However, the net efficiency gain from the use of VFDs on condensate pumps (0.014% to 0.028%) is considered marginal. The marginal benefit is due to the facility being base loaded with condensate pumps design and operation being at a very efficient point on the pump curve. The investment of $750,000 - $1,250,000 is not able to be recovered in current operating conditions. The comparison of

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[1] THE BABCOCK AND WILCOX COMPANY, STEAM/ITS GENERATION AND USE 25-19 (Gregory L. Tomei ed., 42nd ed. 2015) (noting that "[v]ariable pitch axial flow fans used in fossil power generating systems can be more efficient than equivalent centrifugal type fans" and "[s]everal major benefits observed from this figure for axial flow fans include … [t]he areas of constant efficiency run parallel to the boiler resistance line resulting in high efficiency over a wide boiler load range …").

marginal HRI with considerable cost do not make it a cost effective project (poor cost/benefit).

Is it technically feasible to apply this HRI at the unit (possibly on other equipment not previously utilizing a VFD)?

Yes

Please specify what piece of equipment (force-draft, induced-draft, pumps, etc.) would using a VFD technology improve the heat rate of the overall unit.

Condensate pumps – potential under very specific circumstances

Provide a detailed explanation why it is not technically feasible.

N/A

What percentage of HRI is achievable by applying this technology to this unit?

Based on operating data and review of the pump curve, it is projected that this application of VFD technology could provide an additional 0.014% to 0.028% heat rate improvement.

Is this percentage of HRI potential outside the range in Table 45CSR44?

Yes – Significant amount of equipment already has variable technologies. Additionally, based on Longview being a base-loaded facility and condensate pumps operating at an efficient load point at full load there is not significant incremental value in this case.

Provide an explanation why the HRI potential is different than the ranges in Table 45CSR44.

Significant amount of equipment already has BAT variable technologies. Additionally, based on Longview operating as a base-loaded facility, the condensate pumps operate at an efficient load point and as such there is not significant incremental value in this case. If the future facility capacity factor changed drastically and the unit was no longer operated as a base-load unit, this technology and application would be reassessed to determine value at that time.

4.3.a.5. Blade Path Upgrades for Steam Turbines:

Has this HRI been previously applied to the EGU?

Yes, as part of base design

What was the start-up date?

2011 original commissioning as part of base design, BAT applied

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

Sustained for life of EGU with proper maintenance and may degrade between maintenance cycles recovering after turbine overhauls

Are there further upgrades or improvements available with this technology?

No, BAT already applied to EGU and no current steam path upgrade for our design

4.3.a.6. Redesign or Replacement of Economizer:

Has this HRI been previously applied to the EGU?

Yes, as part of base design

What was the start-up date?

2011 original commissioning as part of base design, BAT applied

What HRI improvement was achieved?

N/A, achieved as part of base design

How much longer will the HRI be observed?

With proper maintenance, performance can be sustained with very small amount of degradation

Are there further upgrades or improvements available with this technology?

No, current BAT applied in base design

4.3.a.7. Improved Operating and Maintenance Practices:

Has this HRI been previously applied to the EGU?

Yes

What was the start-up date?

Training began in 2013 and is ongoing.

What HRI improvement was achieved?

The facility uses a modern Computerized Managed Maintenance System (CMMS) (Maximo) to manage all maintenance activities. Additionally, a real-time ASME thermodynamic model is utilized to continuously monitor and assess unit performance including heat rate in an effort to prevent and/or mitigate performance degradation due to a variety of factors. This model is utilized by personnel both on site and remotely on a daily basis to track and adjust unit parameters to maintain optimal performance. Additionally, advanced monitoring and diagnostics with an artificial intelligence learning system is utilized continuously to identify changes in process that can impact reliability and performance of the facility. Longview utilizes 3rd party subject matter experts for performance to help troubleshoot or identify any abnormal operation or condition.

Having a well trained staff with knowledge on heat rate and efficiency principles is an enabler of sustained results. Training of all personnel was completed in 2013 with ongoing continuous employee knowledge development and continuous improvement. This training and fundamental knowledge is a baseline enabler of insuring the unit remains efficient and continuously improves. Unit performance is deeply embedded in the culture of the facility.

What was the cost to install?

Initial training with vendor in 2013 was approx. $30k in direct costs. The cost of our internal labor and lost time of labor in training is not part of cost. Ongoing training fits in the annual budget of employee development.

How much longer will the HRI be observed?

Sustained for life with appropriate ongoing communication and training

Are there further upgrades or improvements available with this technology?

Not at this time. Ongoing training will continue as warranted to ensure facility personnel have adequate knowledge to continue to effectively support the program.

4.4. The owner or operator shall propose and justify a standard of performance for each unit in the permit application that satisfies the following requirements:

The facility proposes the following:

4.4.a. Standard of Performance

The Longview Power PC EGU shall emit no more than 2,049 lbs/Mwh (net) CO_2 on a 3 year rolling annual average basis for an operating Net Output Factor (NOF) greater than 95%. Net Output Factor is a standard within NERC's Generation Availability Data System (GADS), a relationship of actual generation divided by maximum potential generation for time period when unit is operating. The standard of performance would require adjustment for any year with a lower NOF to account for lower efficiencies that occur at lower loads. Mwh (net) shall be calculated by measuring the auxiliary load at the auxiliary transformers Mwh (aux) and subtracting from the Gross MW reading Mwh (gross) with removal of non-production related auxiliary loads.

Compliance shall be determined by:

1. Calculating the CO_2 emissions on an hourly arithmetic average basis:

   CO_2 (lbs/hr) = 5.7e-7 * CO_2 (ppm) * Flow (Scfh) / 2000

   CO_2 lbs/Mwh (net) = CO_2 (lbs/hr) / Mwh (Net)

   Mwh (Net) = Mwh (gross) – Mwh (aux)

2. Calculating an annual average based on all operating hours

3. Calculating a rolling 3-year annual average CO_2 lb/Mwh (net) rate

Data obtained during startup, shutdown, malfunction, or hourly periods of < 40% unit load shall be excluded from calculations.

The Standard of Performance target CO_2 lbs/Mwh (net) shall be increased at a rate of 2% every 5 years (+0.4% annually) to account for inevitable equipment efficiency losses over the life of the EGU.

4.4.b. Justification

After assessing the typical unit performance from 2012 to 2019, a baseline heat rate and in turn CO_2 rate was calculated based on validated CEMS data covering the time period from 2014 – 2019. Once this average was calculated, the standard deviation of the data set was then calculated, multiplied by three (3), and added to the six year average, creating a standard of performance representative to the actual unit of performance, and allowing for an appropriate level of variability. A summary of these calculations is provided in Table 2 below:

Table 2 - LVP Heat Rate and CO_2 Data

Period	OPM Heat Rate	CO_2
	Btu/Kwh, HHV	*lbs/Mwh*
2014	8,990	2,004
2015	8,938	1,943
2016	8,897	1,946
2017	8,783	1,947
2018	8,757	1,921
2019	8,684	1,899
Average	***8,842***	***1,943***
SD	***118***	***35***
Ave+3SD	**9,196**	**2,049**

4.4.c. Compliance/Averaging Period

The compliance period shall be based on a three (3) year rolling annual average.

4.4.d. Compliance Schedule

The Longview Power PC EGU would demonstrate compliance beginning in the first full calendar year after permit issuance.

4.4.e. Monitoring

CO_2 (ppm) output concentrations shall be measured according to the provisions of 40 CFR Part 60.49Da(d).

Flow (scfh) shall be measured according to the provisions of 40 CFR Part 60.49Da(m).

Mwh (gross) shall be measured according to the provisions of 40 CFR Part 60.49Da(k).

4.4.f. Recordkeeping

Records shall be maintained for a minimum of 5 years via the CEMS/DAHS.

4.4.g. Reporting

CO_2 mass reporting (lbs/Mwh net) shall occur on an annual basis via a report submitted to EPA and WVDEP.

4.5 In applying a standard of performance to an affected steam generating unit, the owner or operator may take into consideration factors, such as the remaining useful life of such affected steam generating unit, provided the owner or operator demonstrates with respect to each such affected steam generating unit (or class of such affected steam generating units):

4.5.a. Unreasonable cost of control resulting from plant age, location, or basic process design;
4.5.b. Physical impossibility of installing necessary control equipment; or
4.5.c. Other unique factors that make application of a less stringent standard or final compliance time significantly more reasonable.

and

4.6 If the owner or operator considered remaining useful life and other factors for a designated facility, the application shall include a summary of how those factors were used in deriving a proposed standard of performance and must include a summary in the application of relevant factors from subsection 4.3 in deriving a proposed standard of performance.

As discussed in further detail herein, Longview has considered each of the BSER technologies and practices specifically enumerated in the ACE rule. Longview has already fully implemented six of the seven BSER technologies and practices. The only identified exception is the possibility of variable frequency drives (VFD) on some facility equipment; however, the technology used instead of VFD is equivalent to or better than VFD. In the very limited instances in which VFD could be added and provide some HRI, i.e. condensate pumps, the expected costs of such a project compared with expected trivial HRI demonstrate that they would not be cost effective projects. Thus, Longview has been unable to identify any further heat rate improvement (HRI) required by the ACE rule.

"Remaining useful life" was not considered in the analysis contained herein. EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. EPA expects this to be a part of many state plans." 84 FED. REG. at 32,554. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO2 reductions. Since Longview has already integrated the BSER technologies contemplated by the ACE rule (or in the case of VFDs an alternative providing even more HRI) into the design, construction and operation of the plant which have successfully achieved both high efficiency and low CO_2 emissions, and with any further trivial potential HRI not being cost effective, Longview is in compliance with the intent of the ACE rule without further HRI.

4.7 The owner or operator of an affected steam generating unit shall submit a compliance schedule with the permit application to the Secretary if the owner or operator requests a compliance date past July 8, 2024.

N/A

4.8 Standards of performance for affected steam generating units proposed in the application shall be demonstrated to be quantifiable, verifiable, permanent, and enforceable with respect to each affected steam generating unit. The application shall include the methods by which each standard of performance meets each of the following requirements:

Longview currently has a complete and effective Continuous Emissions Monitoring System (CEMS) that is monitored by applicable agencies. This system is subject to:

- Frequent calibration, effective maintenance and RATA testing
- Heat Rate degradation and improvements are currently monitored, evaluated and repaired/confirmed.
- Longview has demonstrated effective maintenance of all systems either routinely and/or through frequent outages.

The CEMS provides for effective monitoring in quantifiable and verifiable means and fully adopted industry practice. The identification and enforcement of non-compliant exceedances related to CO_2 would be reported and handled as current NOx and SO_2 issues. From a plant operations perspective, Longview would maintain compliance by continuing to use industry standard and regulatory compliant methods, as appropriate, and as the facility currently does for other air-related regulatory programs and standards.

A permit issued pursuant to this application will also make all standards of performance to be sufficiently "permanent" and "enforceable."

4.9 The application shall include the information listed below, as applicable:

4.9.a. A summary of each designated facility's anticipated future operation characteristics, including:

4.9.a.1. Annual generation;

4.9.a.2. CO_2 emissions;

4.9.a.3. Fuel use, fuel prices, fuel carbon content;

4.9.a.4. Fixed and variable operations and maintenance costs;

4.9.a.5. Heat rates; and

4.9.a.6. Electric generation capacity and capacity factors.

4.9.b. A timeline for implementation.

4.9.c. All wholesale electricity prices.

4.9.d. A time period of analysis, which must extend through at least 2035.

Longview is one of the lowest cost fossil fired generators in the PJM market place and thus is currently a base load unit. Many times, this facility dispatches ahead of most all gas fired combined cycle facilities. The ability to reliably deliver power under extreme cold weather with a secured fuel source provides the grid with the essential resilience and affordability.

The future of an open and competitive market place isn't subject to definitive future outcomes and, therefore, cannot be effectively forecasted to gain certainty to generation patterns, capacity factors, electric power prices, fuel use patterns or consumptions. Since these cannot be gained in a certain manner, maintenance efforts and associated costs cannot be accurately determined.

It is because of this reasoning that Longview can only forecast what a near-term expectation of net generation, capacity factors and maintenance requirements will be. Those detailed forecasts are critical and vital to Longview's competitiveness and are considered proprietary and confidential.

Given these limitations, and a projected unit service life of approximately 30 to 40 years, Longview believes that the future operations for this facility will remain as a base load unit with relatively high capacity factors and that maintenance efforts will remain sufficient to sustain reliability, compliance and safety of the facility well into the future. Any further attempted prediction of future operations is impossible; however, to do its best to comply with ACE rule and W. Va. C.S.R. § 45-44-4 requirements, Longview prepared Table 3 below which is a current estimate of expected future operation. Of note, the proposed substantive terms in this application are not contingent upon any prediction of future operation or factor. Thus, the information sought in W. Va. C.S.R. § 45-44-4.4.9 (and its inherent uncertainty) are not expected to be "applicable" as they do not affect this application and a permit issued pursuant to it.

Table 3 - LVP Anticipated Future Operation Characteristics

45CSR44 Reference	Parameter	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4.9.a.1.	Annual Net Generation (GWh)	5,087	5,250	5,410	5,174	5,124	5,368	5,423	5,514	5,470	5,191	5,571	5,454	5,416	5,290	4,991	5,548
4.9.a.2.	CO2 Emissions (000 tons)	5,212	5,400	5,587	5,365	5,286	5,560	5,640	5,757	5,734	5,415	5,834	5,734	5,717	5,606	5,311	5,874
4.9.a.3.	Fuel Use (000 tons)	1,758	1.822	1,885	1,810	1,783	1,876	1,903	1,942	1,934	1,827	1,968	1,935	1,929	1,891	1,792	1,982
4.9.a.3.	Fuel Carbon Content (000 tons)	1,231	1,275	1,319	1,267	1,248	1,313	1,332	1,360	1,354	1,279	1,378	1,354	1,350	1,324	1,254	1,387
4.9.a.5.	Heat Rates (btu/kWh)	8,815	8,851	8,886	8,922	8,877	8,912	8,948	8,984	9,020	8,975	9,011	9,047	9,083	9,119	9,156	9,110
4.9.a.6.	Electric Generation Capacity	6,149	6,132	6,132	6,132	6,149	6,132	6,132	6,132	6,149	6,132	6,132	6,132	6,149	6.132	6,132	6,132
4.9.a.6.	Capacity Factor	83%	86%	88%	84%	83%	88%	88%	90%	89%	85%	91%	89%	88%	86%	81%	90%