MISSOURI
DEPARTMENT OF
NATURAL RESOURCES

**MISSOURI AIR CONSERVATION COMMISSION**

# PERMIT TO CONSTRUCT

Under the authority of RSMo 643 and the Federal Clean Air Act the applicant is authorized to construct the air contaminant source(s) described below, in accordance with the laws, rules and conditions as set forth herein.

Permit Number: 112016-004 Project Number: 2016-05-065

Installation Number: 019-0004

Parent Company: Curators of the University of Missouri (MU)

Parent Company Address: 8 Research Park Development Building, MU Environmental Health & Safety, Columbia, MO 65211

Installation Name: MU Power Plant

Installation Address: Fifth & Stewart Streets, Columbia, MO 65211

Location Information: Boone County, S13, T48N, R13W

Application for Authority to Construct was made for:
New natural gas burners in existing boiler 10, and an installation-wide 2,000 tpy $SO_2$ limit. This review was conducted in accordance with Section (5), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*.

☐ Standard Conditions (on reverse) are applicable to this permit.

☑ Standard Conditions (on reverse) and Special Conditions are applicable to this permit.

Prepared by
David Little, PE
Environmental Engineer III
New Source Review Unit

Director or Designee
Department of Natural Resources
NOV 08 2016

Effective Date

STANDARD CONDITIONS:

Permission to construct may be revoked if you fail to begin construction or modification within two years from the effective date of this permit. Permittee should notify the Enforcement and Compliance Section of the Air Pollution Control Program if construction or modification is not started within two years after the effective date of this permit, or if construction or modification is suspended for one year or more.

You will be in violation of 10 CSR 10-6.060 if you fail to adhere to the specifications and conditions listed in your application, this permit and the project review. In the event that there is a discrepancy between the permit application and this permit, the conditions of this permit shall take precedence. Specifically, all air contaminant control devices shall be operated and maintained as specified in the application, associated plans and specifications.

You must notify the Enforcement and Compliance Section of the Department's Air Pollution Control Program of the anticipated date of start up of this (these) air contaminant source(s). The information must be made available within 30 days of actual startup. Also, you must notify the Department's regional office responsible for the area within which you are located within 15 days after the actual start up of this (these) air contaminant source(s).

A copy of the permit application and this permit and permit review shall be kept at the installation address and shall be made available to Department's personnel upon request.

You may appeal this permit or any of the listed special conditions to the Administrative Hearing Commission (AHC), P.O. Box 1557, Jefferson City, MO 65102, as provided in RSMo 643.075.6 and 621.250.3. If you choose to appeal, you must file a petition with the AHC within 30 days after the date this decision was mailed or the date it was delivered, whichever date was earlier. If any such petition is sent by registered mail or certified mail, it will be deemed filed on the date it is mailed. If it is sent by any method other than registered mail or certified mail, it will be deemed filed on the date it is received by the AHC.

If you choose not to appeal, this certificate, the project review and your application and associated correspondence constitutes your permit to construct. The permit allows you to construct and operate your air contaminant source(s), but in no way relieves you of your obligation to comply with all applicable provisions of the Missouri Air Conservation Law, regulations of the Missouri Department of Natural Resources and other applicable federal, state and local laws and ordinances.

The Air Pollution Control Program invites your questions regarding this air pollution permit. Please contact the Construction Permit Unit using the contact information below.

<u>Contact Information</u>:
Missouri Department of Natural Resources
Air Pollution Control Program
P.O. Box 176
Jefferson City, MO 65102-0176
(573) 751-4817

The regional office information can be found at the following website:
http://dnr.mo.gov/regions/

SPECIAL CONDITIONS:
The permittee is authorized to construct and operate subject to the following special conditions:

*The special conditions listed in this permit were included based on the authority granted the Missouri Air Pollution Control Program by the Missouri Air Conservation Law (specifically 643.075) and by the Missouri Rules listed in Title 10, Division 10 of the Code of State Regulations (specifically 10 CSR 10-6.060). For specific details regarding conditions, see 10 CSR 10-6.060 paragraph (12)(A)10. "Conditions required by permitting authority."*

MU Power Plant
Boone County, S13, T48N, R13W

1. Natural Gas Requirement
   The four burners in Boiler 10 (EP-10) shall be fired exclusively with pipeline natural gas as defined in 40 CFR 72.2. MU shall demonstrate compliance by obtaining documentation from the fuel supplier for all fuels fired in the four burners. All records shall be kept on site.

2. Heat Input Limitation
   A. The combined maximum rating of all fuel capability in Boiler 10 shall not exceed 269.4 MMBtu/hr input, on a 1-hour average.

   B. MU shall notify the Permits Section in writing before the initial startup of the Boiler 10 natural gas burners of any changes to the as-built maximum rating from the permitted 269.4 MMBtu/hr input.

   C. MU shall submit an as-built report to the Permits Section within 180 days of initial startup of the Boiler 10 natural gas burners. The report shall contain at minimum the installed make, model, and maximum rating of each Boiler 10 natural gas burner. The report shall be accompanied with a copy of the burner manufacturer design specifications that show the make, model, and maximum rating. The report shall be accompanied with boiler/burner manufacturer design specifications or other engineering calculations that show the combined maximum rating of all fuel capability in Boiler 10 cannot exceed the value in Special Condition 2.A.

3. $NO_X$ Emission Limitation
   A. MU shall emit less than 395.79 tons of $NO_X$ in any consecutive 12-month period from Boiler 10, inclusive of startup, shutdown, and malfunction.

   B. MU shall develop and use forms to demonstrate compliance with Special Condition 3.A. The forms shall contain at a minimum the following information,
      1) Installation name
      2) Installation ID
      3) Emission unit
      4) Current month
      5) Current 12-month date range
      6) Monthly throughput of each fuel fired in Boiler 10

SPECIAL CONDITIONS:
The permittee is authorized to construct and operate subject to the following special conditions:

7) Respective fuel NOx emission factors
   a) The most recent $NO_X$ emission factors approved by the Air Pollution Control Program shall be used. Prior to testing, the $NO_X$ emission factors in Table 1 shall be used.

Table 1: $NO_X$ Emission Factors

| Fuel | Emission Factor | Units of Measure |
|---|---|---|
| Natural gas | 173.4 | Lb/MMCF |
| Bituminous Coal | 9.52 | Lb/ton |
| Biomass (wood chips) | 1.50 | Lb/ton |
| Tire Derived Fuel (TDF) | * 5.97 | Lb/ton |

* obtained from 2010 EIQ

   b) When MU tests $NO_X$ emissions from Boiler 10 in accordance with this permit, MU shall develop new $NO_X$ emission factors to demonstrate compliance with Special Condition 3.A. The tested emission factors may be used retroactively to replace the issued emission factors if approved to do so by the Air Pollution Control Program.

8) Monthly emissions for each fuel calculated using the following equation:

$$NOx\ emissions\ (tons) = fuel\ fired\ (tons\ or\ MMCF) \times fuel\ specific\ emission\ factor\ \left(\frac{lb\ NOx}{ton\ or\ MMCF\ of\ fuel\ fired}\right) \times \left(\frac{1\ ton\ NOx}{2000\ lbs\ NOx}\right)$$

9) Monthly $NO_X$ emissions calculated by summing $NO_X$ emissions from all fuels
10) 12-month rolling total $NO_X$ emissions and the sum of all $NO_X$ emissions from startup, shutdown, and malfunction as reported to the Air Pollution Control Program's Compliance/Enforcement Section
11) Indication of compliance with Special Condition 3.A.

4. CO Emission Limitation
   A. MU shall emit less than 149.59 tons of CO in any consecutive 12-month period from Boiler 10, inclusive of startup, shutdown, and malfunction.

   B. MU shall develop and use forms to demonstrate compliance with Special Condition 4.A. The forms shall contain at a minimum the following information,
      1) Installation name
      2) Installation ID

SPECIAL CONDITIONS:
The permittee is authorized to construct and operate subject to the following special conditions:

3) Emission unit
4) Current month
5) Current 12-month date range
6) Monthly throughput of each fuel fired in Boiler 10
7) Respective fuel CO emission factors
   a) The most recent CO emission factors approved by the Air Pollution Control Program shall be used. Prior to testing, the CO emission factors in Table 2 shall be used.

Table 2: CO Emission Factors

| Fuel | Emission Factor | Units of Measure |
|---|---|---|
| Natural gas | 84.0 | Lb/MMCF |
| Bituminous Coal | 1.234 | Lb/ton |
| Biomass (wood chips) | 13.6 | Lb/ton |
| TDF | 6.0 | Lb/ton |

   b) When MU tests CO emissions from Boiler 10 in accordance with this permit, MU shall develop new CO emission factors to demonstrate compliance with Special Condition 4.A. The tested emission factors may be used retroactively to replace the issued emission factors if approved to do so by the Air Pollution Control Program.

8) Monthly emissions for each fuel calculated using the following equation:

$$CO\ emissions\ (tons) = fuel\ fired\ (tons\ or\ MMCF) \times fuel\ specific\ emission\ factor\ \left(\frac{lb\ CO}{ton\ or\ MMCF\ of\ fuel\ fired}\right) \times \left(\frac{1\ ton\ CO}{2000\ lbs\ CO}\right)$$

9) Monthly CO emissions calculated by summing CO emissions from all fuels
10) 12-month rolling total CO emissions and the sum of all CO emissions from startup, shutdown, and malfunction as reported to the Air Pollution Control Program's Compliance/Enforcement Section
11) Indication of compliance with Special Condition 4.A.

5. $SO_2$ Emission Limitation
   A. MU shall emit less than 2,000 tpy of $SO_2$ in calendar year 2017 and each calendar year thereafter from the entire installation as defined in Attachment A, inclusive of startup, shutdown, and malfunction.

SPECIAL CONDITIONS:
The permittee is authorized to construct and operate subject to the following special conditions:

B. MU shall develop and use forms to demonstrate compliance with Special Condition 5.A. The forms shall contain at a minimum the following information,
1) Installation name
2) Installation ID
3) Emission unit
4) Current month
5) Current 12-month date range
6) Monthly throughput of each fuel fired in each emission unit in Attachment A
7) $SO_2$ emission factors
   a) The most recent $SO_2$ factors approved by the Air Pollution Control Program shall be used. Prior to testing, the $SO_2$ emission factors in Attachment A shall be used.
   b) When MU tests fuel sulfur weight % in accordance with this permit, MU shall develop new $SO_2$ emission factors to demonstrate compliance with Special Condition 5.A. The new $SO_2$ emission factors may be based upon the monthly weighted average of respective fuel sulfur weight % and respective fuel usage. The tested emission factors may be used retroactively to replace the issued emission factors if approved to do so by the Air Pollution Control Program.
8) Monthly emissions for each fuel calculated using the following equation:

$$SO2\ emissions\ (tons) = fuel\ fired\ (tons, MMCF, gal) \times fuel\ specific\ emission\ factor\ \left(\frac{lb\ SO2}{ton, MMCF, gal\ of\ fuel\ fired}\right) \times \left(\frac{1\ ton\ SO2}{2000\ lbs\ SO2}\right)$$

9) Emission unit specific monthly $SO_2$ emissions calculated by summing $SO_2$ emissions from all fuels for that unit
10) Monthly $SO_2$ emissions calculated by summing $SO_2$ emissions from all emission units
11) Calendar year total $SO_2$ emissions and the sum of all $SO_2$ emissions from startup, shutdown, and malfunction as reported to the Air Pollution Control Program's Compliance/Enforcement Section
12) Indication of compliance with Special Condition 5.A.

6. Emission Testing

A. MU shall test Boiler 10 for the scenarios in Table 3. Each fuel shall be tested independently of the other fuel, except for biomass which is only fired with other solid fuel.

SPECIAL CONDITIONS:
The permittee is authorized to construct and operate subject to the following special conditions:

Table 3: Boiler 10 Testing, Fuels and Pollutants

| Fuel | NOx | CO |
|---|---|---|
| Natural Gas | x | x |
| Coal | x | x |
| Biomass | x | x |
| TDF | x | x |

TDF has not been fired in recent years. TDF testing shall only be required if TDF will be reintroduced.

B. All tests shall be performed at the maximum capacity, 269.4 MMBtu/hr input. If it is impractical to test at maximum capacity, testing may be performed at less than the maximum capacity; in this case, subsequent operation of Boiler 10 on that fuel is limited to 110 percent of the test rate until a new test is conducted. Once Boiler 10 is so limited, operation at higher capacities on that fuel is allowed for no more than 15 total days for the purpose of additional compliance testing to regain the authority to operate at the maximum capacity of that fuel.

C. Natural gas initial testing shall be performed within 60 days after achieving the maximum capacity. Natural gas initial testing shall be performed not later than 180 days after initial start-up for commercial operation.

D. Coal initial testing shall be performed within 180 days of this permit's issuance.

E. A completed Proposed Test Plan Form (enclosed) must be submitted to the Air Pollution Control Program 30 days prior to the proposed test date so that the Air Pollution Control Program may arrange a pretest meeting, if necessary, and assure that the test date is acceptable for an observer to be present. The Proposed Test Plan may serve the purpose of notification and must be approved by the Director prior to conducting the required emission testing. Each proposed test method shall be approved by the Air Pollution Control Program prior to conducting the respective test.

F. One written copy and one electronic copy of the $NO_X$ and CO performance test results shall be submitted to the Director within 60 days of completion of any required testing. The report must include legible copies of the raw data sheets, analytical instrument laboratory data, and complete sample calculations from the required EPA Method for at least one sample run. The report shall also include the following values present during each test:

1) Natural gas
   a) Fuel usage [cubic feet (CF)/hr]
   b) HHV (Btu/CF)
   c) Tested firing rate (MMBtu/hr input)
2) Coal, Biomass, and TDF
   a) Fuel usage (tph)

SPECIAL CONDITIONS:
The permittee is authorized to construct and operate subject to the following special conditions:

b) HHV (Btu/lb)
c) Tested firing rate (MMBtu/hr input)

G. Subsequent testing of each fuel in Table 3 shall be conducted at least once every three calendar years, with no two consecutive tests of the same fuel and same pollutant within 12 months (e.g. coal NOx and CO can be tested within 12 months, coal and natural gas NOx can be tested within 12 months, but coal $NO_X$ cannot be tested twice within 12 months to represent three years).

7. Fuel Sulfur Testing
MU shall keep vendor records representative of each coal, fuel oil/diesel, biomass, and TDF sulfur weight %. A change of materials or vendors requires new vendor records. As an alternative to vendor sulfur records, MU may conduct representative sulfur testing on each fuel delivery. All records shall be kept on site.

8. Record Keeping and Reporting Requirements

A. MU shall maintain all records required by this permit for not less than five years and shall make them available immediately to any Missouri Department of Natural Resources' personnel upon request. These records shall include SDS for all materials used.

B. MU shall report to the Air Pollution Control Program's Compliance/Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than 10 days after the end of the month during which any record required by this permit shows an exceedance of a limitation imposed by this permit.

REVIEW OF APPLICATION FOR AUTHORITY TO CONSTRUCT AND OPERATE
SECTION (5) REVIEW
Project Number: 2016-05-065
Installation ID Number: 019-0004
Permit Number: **112016-004**

Installation Address:
MU Power Plant
Fifth & Stewart Streets

Columbia, MO 65211

Parent Company:
Curators of the University of Missouri (MU)
8 Research Park Development Building, MU
Environmental Health & Safety
Columbia, MO 65211

Boone County, S13, T48N, R13W

REVIEW SUMMARY

- MU Power Plant has applied for authority to install new natural gas burners in existing boiler 10, and an installation-wide 2,000 tpy $SO_2$ limit.

- The application was deemed complete on June 17, 2016.

- HAP emissions are expected from natural gas combustion. Potential HAP emissions from the new burners are below major source levels and below respective SMAL.

- None of the NSPS apply to Boiler 10.
    - 40 CFR 60 Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971*, does not apply. Construction commenced in 1970. The Air Pollution Control Program is not aware if there have been any activities at the boiler that would satisfy NSPS modification or reconstruction, prior to this project. The new burners do not satisfy NSPS modification or reconstruction.
    - 40 CFR 60 Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, does not apply. The reason is the same as for Subpart D.
    - 40 CFR Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*, does not apply. The reason is the same as for Subpart D. Also, Boiler 10 is a fossil fuel-fired unit that cogenerates steam and electricity. However, it does not supply more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale. Therefore it is not considered an electric utility steam generating unit.
    - 40 CFR 60 Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, does not apply. The reason is the same as for Subpart D. Also, Boiler 10's maximum heat input is greater than 100 MMBtu/hr.

- None of the NESHAPs under 40 CFR 61 apply to Boiler 10.

- 40 CFR 63 Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, applies to Boiler 10.

- 40 CFR 63 Subpart UUUUU, *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, does not apply to Boiler 10. Boiler 10 is a fossil fuel-fired unit that cogenerates steam and electricity. However, it does not supply more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale. Therefore it is not considered an electric utility steam generating unit.

- Emission controls are associated with this project. The new natural gas burners may be classified as low $NO_X$, but the classification does not change this permit.

- This review was conducted in accordance with Section (5) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required.* The $NO_X$ and CO increases are conditioned below de minimis levels.

- This installation is located in Boone County, an attainment area for all criteria pollutants.

- This installation is on the List of Named Installations found in 10 CSR 10-6.020(3)(B), Table 2. The installation is classified as item number 21. Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input. The installation's major source level is 100 tons per year and fugitive emissions are counted toward major source applicability.

- Ambient air quality modeling was not performed since potential emissions of the project are conditioned below de minimis levels.

- Emission testing is required for Boiler 10 as a part of this permit. Testing may be required as part of other state, federal or applicable rules.

- Submittal of an application to amend the Part 70 operating permit is required within one year of this permit's issuance.

- Approval of this permit is recommended with special conditions.

## INSTALLATION DESCRIPTION

The University of Missouri operates a combined heat and power facility to generate steam and electricity to serve the MU campus. It is a major source of PM, $PM_{10}$, $PM_{2.5}$, $SO_2$, NOx, CO, GHG, and HAPs for construction permits and a Part 70 source for operating permits. The following construction permits have been issued to MU Power Plant from the Air Pollution Control Program.

Table 4: Permit History

| Permit Number | Description |
|---|---|
| 0886-004 | Major review for installation of Boiler 11. |
| 0294-018 | Installation of emergency generator for North Well. |
| 0494-020 | Major review for installation of Boiler 12. |
| 0296-007 | Installation of emergency generator for Southwest Well and twin fuel oil storage tanks. |
| 1096-021 | Replacement IC engine for East Well. |
| 0697-002 | Installation of solvent-based parts washer. |
| 072000-005 | Major review for installation of two turbines, two duct burners, and a back-up diesel generator. |
| 072000-005A | Amendment to change CEMS requirements. |
| 042007-019 | Temporary permit to burn biomass fuel in boiler. |
| 032008-002 | Replacement of four existing cooling towers with a new cooling tower and a closed loop cooling system cooling tower. |
| 042007-019A | Addition of a feedwagon for temporary burning of biomass. |
| 032008-002A | Amendment to remove the closed loop heat-exchanger cooling tower, lower the drift loss limit to less than 0.0010% for the remaining cooling tower. |
| 042010-002 | Replacement of Boiler 11 with biomass-fired bubbling fluidized bed boiler (BFB-1) |
| 042010-002A | Correction of the NOx limit in Table 5. |
| 042010-002B | Amendment to clarify that silt loading testing is not required until startup of BFB-1. |
| 042010-002C | Amendment to temporarily allow operation of BFB-1 fuel handling/storage system without the baghouse. |
| 032008-002B | Amendment to remove monthly TDS sampling requirement. |
| 092015-001 | Increased hydrated lime injection for boilers 7, 8, 9, 10. |
| 092015-001A | Amendment for ash silo. |
| pending | Project 2014-07-050 for fuel handling at BFB-1. |
| pending | Project 2015-07-058 for changes at BFB-1. |

## PROJECT DESCRIPTION

MU proposes to replace the four existing natural gas burners in Boiler 10 with four new natural gas burners. There will also be new gas fuel trains, a new burner management control system, and modifications to the existing windboxes and dampers. The existing burners have not operated in the last 10 years or longer according to fuel records in the EIQ. The new burners are proposed to sum to the exact same capacity as the existing boiler, 269.4 MMBtu/hr input. The boiler is a spreader stoker unit, and will be able to simultaneously co-fire gas and solid fuels. A special condition ensures boiler capacity is not increasing.

MU also proposes to limit installation wide $SO_2$ emissions to less than 2,000 tpy as a compliance option with the 40 CFR 51 Subpart BB, *Data Requirements for Characterizing Air Quality for the Primary $SO_2$ NAAQS*, §51.1203(e)(1).

EMISSIONS/CONTROLS EVALUATION

The $NO_X$ and CO emission factors were obtained from MU, citing vendor data. According to MU, the burner contract is for 0.10 lb NOx/MMBtu and 0.037 lb CO/MMBtu initially. MU requested the use of 0.17 lb NOx/MMbtu and 0.08 lb CO/MMBtu for permitting.

Potential $NO_X$ emissions from the new burners are 200.6 tpy, which exceeds the PSD significant emission rate (SER) / de minimis level of 40.0 tpy. Baseline actual emissions (BAE) are 355.79 tpy, obtained from the 2008-2007 EIQ. Reported emissions from years 2008, 2007, and 2006 used an emission factor obtained from the EPA document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition, Chapter 1, *External Combustion Sources*. The AP-42 emission factor is higher than the site specific, 2009 tested factor of 9.52 lb/ton (value after correcting to 7% $O_2$). The 2008-2006 reported emissions were adjusted downward for usage in this permit to reflect the lower, tested emission factor. A test was conducted in 1991 resulting in a higher factor, but the 2009 test was deemed more representative. PTE minus BAE would exceed the PSD SER. Therefore, MU elected to limit the project $NO_X$ emissions increase to less than 40 tpy above BAE. Boiler 10 total $NO_X$ emissions are limited to less than 395.79 tpy in any consecutive 12-month period.

Potential CO emissions from the new burners are 97.17 tpy when using the emission factor of 84 lb/MMCF. This factor was obtained from the EPA document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition, Table 1.4-1, July 1998. The AP-42 factor is slightly higher than the factor MU requested, 81.6 lb/MMCF. Due to the possible increases in CO that low $NO_X$ burners can create, CO emissions were conservatively assumed to increase above the PSD SER of 100 tpy. BAE are 49.59 tpy, obtained from the adjusted 2010-2009 EIQ. Reported emissions from years 2008, 2007, and 2006 used an emission factor obtained from the EPA document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition, Chapter 1, *External Combustion Sources*. The AP-42 emission factor is higher than the site specific, 2009 tested factor of 1.2337 lb/ton (value after correcting to 7% $O_2$). The 2008-2006 reported emissions were adjusted downward for usage in this permit to reflect the lower, tested emission factor. The project CO emissions increase was limited to less than 100 tpy above BAE. Boiler 10 total CO emissions are limited to less than 149.59 tpy in any consecutive 12-month period.

Due the complex combustion relationships, limiting $NO_X$ was not assumed to proportionately reduce CO or any other pollutant in Boiler 10. Any emission reductions from the 2,000 tpy $SO_2$ installation wide limit were not relied upon for other pollutants in this permit.

Potential emissions of PM, $PM_{10}$, $PM_{2.5}$, $SO_2$, VOC, HAPs, and GHG from the new burners were calculated using emission factors obtained from AP-42, Chapter 1.4, *Natural Gas Combustion*, July 1998. GHG emission factors from 40 CFR 98 were not used as they result in slightly lower potential emissions compared to AP-42, and the permit represents potential emissions. GHG ($CO_2e$) emissions exceed the subject to regulation threshold, but at the time of this permit's issuance GHG emissions alone cannot subject a project to PSD review. Potential emissions of all pollutants were below deminimis at 8,760 hours per year, and no further calculation method or limit was required.

The baghouse for boiler 10 will be operated during natural gas combustion, as there is currently no flue bypass. However, if solid fuel capability is removed, then the baghouse may be removed. Conservatively, the project emissions do not consider filterable PM, $PM_{10}$ and $PM_{2.5}$ emissions reductions from the baghouse. The special conditions for this permit do not require baghouse operation during natural gas combustion. The special conditions for permit 012015-001 require baghouse operation. However, since that permit predated the installation of the natural gas burners, then that special condition does not apply to the natural gas combustion.

The project emissions increase in Table 5 was only calculated based upon the new natural gas burners. Traditionally, a boiler is considered one emission unit, even if has separate, independent fuel capabilities. As an emission unit being modified by installing new natural gas burners, a calculation method would have been PTE of the affected boiler (or projected actuals of the affected boiler) minus baseline actual emissions. PTE and projected actuals would include all fuels, not just natural gas. Solid fuel usage is expected to decrease in order to meet the 2,000 tpy $SO_2$ limit. The PTE and projected actual emissions from solid fuel usage would likely be less than the baseline emissions. Therefore the project emissions increase in Table 5 should be conservatively high.

The following table provides an emissions summary for this project. Existing potential emissions were not readily available and were assumed major based upon reported actual emissions. Existing actual emissions were obtained from the installation's 2015 EIQ, unless noted otherwise. The project emissions increase for $NO_X$ and CO represents the limited deminimis increase. The project emissions increase for other pollutants represents the potential of the new burners at 8,760 hours per year of operation.

Table 5: Emissions Summary (tpy)

| Pollutant | Regulatory *De Minimis* Levels | Existing Potential Emissions | Existing Actual Emissions (2015 EIQ) | Project Emissions Increase | New Installation Conditioned Potential |
|---|---|---|---|---|---|
| PM | 25.0 | Major | N/D | 2.20 | Major |
| $PM_{10}$ | 15.0 | Major | 68.20 | 8.79 | Major |
| $PM_{2.5}$ | 10.0 | Major | 64.83 | 8.79 | Major |
| $SO_2$ | 40.0 | Major | 3,772.38 | 0.69 | < 2,000 |
| NOx | 40.0 | Major | 414.63 | < 40.0 | Major |
| VOC | 40.0 | N/D | 3.84 | 6.36 | N/D |
| CO | 100.0 | Major | 93.11 | < 100.0 | Major |
| GHG ($CO_2e$) | 75,000 | Major | [2] 343,326 | 139,645 | Major |
| GHG (mass) | 100 | Major | [2] 340,454 | 138,820 | Major |
| Combined HAPs | 25.0 | Major | 35.18 | 2.18 | Major |
| Hexane | 10.0 | N/D | N/D | 2.08 | N/D |
| Formaldehyde | [1] 2.0 | N/D | N/D | 0.09 | N/D |

N/A = Not Applicable; N/D = Not Determined

[1] SMAL
[2] GHG emissions obtained from the EPA facility level information on greenhouse gases tool, 2014, including biogenic $CO_2$.

## PERMIT RULE APPLICABILITY

This review was conducted in accordance with Section (5) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required.* The $NO_X$ and CO increases are conditioned below de minimis levels.

## APPLICABLE REQUIREMENTS

MU Power Plant shall comply with the following applicable requirements. The Missouri Air Conservation Laws and Regulations should be consulted for specific record keeping, monitoring, and reporting requirements. Compliance with these emission standards, based on information submitted in the application, has been verified at the time this application was approved. For a complete list of applicable requirements for your installation, please consult your operating permit.

## GENERAL REQUIREMENTS

- *Start-Up, Shutdown, and Malfunction Conditions*, 10 CSR 10-6.050
- *Submission of Emission Data, Emission Fees and Process Information,* 10 CSR 10-6.110
- *Operating Permits*, 10 CSR 10-6.065
- *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin*, 10 CSR 10-6.170
- *Restriction of Emission of Visible Air Contaminants*, 10 CSR 10-6.220
- *Restriction of Emission of Odors*, 10 CSR 10-6.165

## SPECIFIC REQUIREMENTS

- *MACT Regulations*, 10 CSR 10-6.075
    - *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters,* 40 CFR Part 63, Subpart DDDDD.

## Attachment A – $SO_2$ Emission Units and Emission Factors

| EIQ Reference | Description | Bituminous Coal (lb/ton) | Natural Gas (lb/MMCF) | Biomass wood chips (lb/MMBtu) | TDF (lb/MMBtu) | Fuel Oil, Diesel, Kerosene (lb / 1,000 gal) |
|---|---|---|---|---|---|---|
| EP07 | Boiler 7 | 38*S | | 0.025 | 1.0 | |
| EP08 | Boiler 8 | 38*S | | 0.025 | 1.0 | |
| EP09 | Boiler 9 | 38*S | 1.5 | 0.025 | 1.0 | |
| EP10 | Boiler 10 | 38*S | 1.5 | 0.025 | 1.0 | |
| EP19 | BFB-1 biomass boiler | | 1.5 | 0.025 | | |
| EP20 | Boiler 12 | | 1.5 | | | 142*S |
| EP18 | North well RICE | | | | | 142*S |
| EP23 | Southwest well RICE | | | | | 142*S |
| EP31 | South well RICE | | 1.5 | | | |
| EP25 | East well RICE | | 1.5 | | | |
| EP26 | Turbine 1: turbine | | 1.5 | | | 142*S |
| | Turbine 1: duct burner | | 1.5 | | | 142*S |
| EP27 | Turbine 2: turbine | | 1.5 | | | 142*S |
| | Turbine 2: duct burner | | 1.5 | | | 142*S |
| EP29 | Power plant back-up RICE | | | | | 142*S |
| EP16 | Kerosene space heaters | | | | | 142*S |

S is sulfur weight %, with % sign removed, e.g. if sulfur content is 0.0015% then S is 0.0015.

Bituminous coal emission factor obtained from AP-42 Table 1.1-3.

Turbine natural gas emission factor obtained from AP-42 Table 3.1-2a (0.94*S lb/MMBtu), 40 CFR 72.2 "pipeline natural gas" definition of 0.5 grains or less of total sulfur per 100 SCF (S = 1.62E-03), natural gas density of 0.044 lb/CF, and HHV of 1,020 Btu/CF. The result is 1.56 lb/MMCF. However all natural gas combustion types should have the same emission factor regardless of the type as long as there is good combustion. $SO_2$ is based upon fuel sulfur content. So, 1.5 lb/MMCF was selected.

RICE natural gas emission factor obtained from AP-42 Chapter 3.2 (5.88E-04 lb/MMBtu based upon sulfur content of 2,000 grains per MMCF), multiplied by the ratio of allowable sulfur in pipeline natural gas to 2,000 grains per MMCF (2.5), and HHV of 1,020 Btu/CF, equals 1.5 lb/MMCF.

Boiler and duct burner natural gas emission factor obtained from AP-42 Table 1.4-2 (0.6 lb/MMCF based upon sulfur content of 2,000 grains per MMCF), multiplied by the ratio of allowable sulfur in pipeline natural gas to 2,000 grains per MMCF (2.5), equals 1.5 lb/MMCF.

Biomass emission factor obtained from AP-42 Table 1.6-2.

TDF emission factor obtained from EPA document, *Burning Tires for Fuel and Tire Pyrolysis: Air Implications*, EPA-450/3-91-024, December 1991, Figure 6-2, 1 lb/MMBtu.

Boiler and duct burner fuel oil emission factor obtained from AP-42 Table 1.3-1 (142*S lb/1,000 gal).

RICE fuel oil emission factor obtained from AP-42 Table 3.4-1 (1.01*S lb/MMBtu). Converted to lb/1,000 gal using HHV of 137,000 Btu/gal, results in 138.37*S lb / 1,000 gal. However, all fuel oil combustion types should have the same emission factor regardless of the type as long as there is good combustion. $SO_2$ is based upon fuel sulfur content. So, 142*S was selected.

Turbine fuel oil emission factor obtained from AP-42 Table 3.1-2a (1.01*S lb/MMBtu). Converted to lb / 1,000 gal using HHV of 137,000 Btu/gal, results in 138.37*S lb / 1,000 gal. However, all fuel oil combustion types should have the same emission factor regardless of the type as long as there is good combustion. $SO_2$ is based upon fuel sulfur content. So, 142*S was selected.

142*S lb/1,000 gal is confirmed by mass balance. Fuel density 7.1 lb/gal, multiplied by 2 parts mass $SO_2$ created for every 1 part mass sulfur combusted.

- *Control of Sulfur Dioxide Emissions*, 10 CSR 10-6.261 applies. This project's natural gas burners are not expected to affect the rule's applicability on Boiler 10.

- *Restriction of Particulate Matter Emissions From Fuel Burning Equipment Used for Indirect Heating*, 10 CSR 10-6.405 applies. This project's natural gas burners are not expected to affect the rule's applicability on Boiler 10.

## STAFF RECOMMENDATION

On the basis of this review conducted in accordance with Section (5), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, it is recommended that this permit be granted with special conditions.

## PERMIT DOCUMENTS

The following documents are incorporated by reference into this permit:

- The Application for Authority to Construct form, dated May 12, 2016, received May 24, 2016, designating Curators of the University of Missouri (MU) as the owner and operator of the installation.
- Emails between Martin Kasper and David Little, June 3, 2016 to October 14, 2016.

# APPENDIX A

## Abbreviations and Acronyms

**%** ........... percent
**°F** ........... degrees Fahrenheit
**acfm** ....... actual cubic feet per minute
**BACT**...... Best Available Control Technology
**BMPs**...... Best Management Practices
**Btu**.......... British thermal unit
**CAM** ....... Compliance Assurance Monitoring
**CAS** ........ Chemical Abstracts Service
**CEMS** ..... Continuous Emission Monitor System
**CFR** ........ Code of Federal Regulations
**CO** .......... carbon monoxide
**$CO_2$**......... carbon dioxide
**$CO_2e$**....... carbon dioxide equivalent
**COMS**..... Continuous Opacity Monitoring System
**CSR**........ Code of State Regulations
**dscf**........ dry standard cubic feet
**EIQ** ......... Emission Inventory Questionnaire
**EP**........... Emission Point
**EPA** ........ Environmental Protection Agency
**EU**........... Emission Unit
**fps** .......... feet per second
**ft** ............ feet
**GACT** ..... Generally Available Control Technology
**GHG** ....... Greenhouse Gas
**gpm** ........ gallons per minute
**gr**........... grains
**GWP** ....... Global Warming Potential
**HAP** ........ Hazardous Air Pollutant
**hr**............ hour
**hp** ........... horsepower
**lb** ........... pound
**lbs/hr**...... pounds per hour
**MACT** ..... Maximum Achievable Control Technology
**$\mu g/m^3$**...... micrograms per cubic meter
**m/s** ......... meters per second
**Mgal** ....... 1,000 gallons
**MW**......... megawatt
**MHDR**..... maximum hourly design rate
**MMBtu** ... Million British thermal units
**MMCF**..... million cubic feet
**MSDS**..... Material Safety Data Sheet
**NAAQS** .. National Ambient Air Quality Standards
**NESHAPs** National Emissions Standards for Hazardous Air Pollutants
**$NO_x$**......... nitrogen oxides
**NSPS**...... New Source Performance Standards
**NSR**........ New Source Review
**PM**.......... particulate matter
**$PM_{2.5}$**....... particulate matter less than 2.5 microns in aerodynamic diameter
**$PM_{10}$** ....... particulate matter less than 10 microns in aerodynamic diameter
**ppm**........ parts per million
**PSD**........ Prevention of Significant Deterioration
**PTE** ........ potential to emit
**RACT** ..... Reasonable Available Control Technology
**RAL**........ Risk Assessment Level
**SCC**........ Source Classification Code
**scfm**....... standard cubic feet per minute
**SDS**........ Safety Data Sheet
**SIC** ......... Standard Industrial Classification
**SIP**.......... State Implementation Plan
**SMAL** ..... Screening Model Action Levels
**$SO_x$**......... sulfur oxides
**$SO_2$**......... sulfur dioxide
**tph**.......... tons per hour
**tpy**.......... tons per year
**VMT**........ vehicle miles traveled
**VOC**........ Volatile Organic Compound

NOV 08 2016

Mr. Martin Kasper
Environmental Compliance Specialist
MU Power Plant
417 South 5th Street
Columbia, MO 65211

RE: New Source Review Permit - Project Number: 2016-05-065

Dear Mr. Kasper:

Enclosed with this letter is your permit to construct. Please study it carefully and refer to Appendix A for a list of common abbreviations and acronyms used in the permit. Also, note the special conditions on the accompanying pages. The document entitled, "Review of Application for Authority to Construct," is part of the permit and should be kept with this permit in your files. Operation in accordance with these conditions, your new source review permit application and with your amended operating permit is necessary for continued compliance. The reverse side of your permit certificate has important information concerning standard permit conditions and your rights and obligations under the laws and regulations of the State of Missouri.

This permit may include requirements with which you may not be familiar. If you would like the department to meet with you to discuss how to understand and satisfy the requirements contained in this permit, an appointment referred to as a Compliance Assistance Visit (CAV) can be set up with you. To request a CAV, please contact your local regional office or fill out an online request. The regional office contact information can be found at the following website: http://dnr.mo.gov/regions/. The online CAV request can be found at http://dnr.mo.gov/cav/compliance.htm.

If you were adversely affected by this permit decision, you may be entitled to pursue an appeal before the administrative hearing commission pursuant to Sections 621.250 and 643.075.6 RSMo. To appeal, you must file a petition with the administrative hearing commission within thirty days after the date this decision was mailed or the date it was delivered, whichever date was earlier. If any such petition is sent by registered mail or certified mail, it will be deemed filed on the date it is mailed; if it is sent by any method other than registered mail or certified mail, it will be deemed filed on the date it is received by the administrative hearing commission, whose contact information is: Administrative Hearing Commission, United States Post Office Building, 131 West High Street, Third Floor, P.O. Box 1557, Jefferson City, Missouri 65102, phone: 573-751-2422, fax: 573-751-5018, website: www.oa.mo.gov/ahc.

If you have any questions regarding this permit, please do not hesitate to contact David Little, at the Department of Natural Resources' Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102 or at (573) 751-4817. Thank you for your attention to this matter.

Sincerely,

AIR POLLUTION CONTROL PROGRAM

Susan Heckenkamp
New Source Review Unit Chief

SH:dlj

Enclosures

c: Northeast Regional Office
PAMS File: 2016-05-065

Permit Number: