STATE OF 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: 122004-007 Project Number: 2003-04-113

Owner: City Utilities of Springfield

Owner's Address: P.O. Box 551, Springfield, MO 65801

Installation Name: City Utilities of Springfield - Southwest Power Station

Installation Address: 5050 West FR 164, Springfield, MO 65619

Location Information: Greene County, S7, T28N, R22W

Application for Authority to Construct was made for:

Installation of a pulverized coal fired boiler with a nominal net electric output of 275 megawatts (2,724 million British Thermal Units per hour) and associated material handling equipment. This review was conducted in accordance with Section (8), 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 (listed as attachments starting on page 2) are applicable to this permit.

DEC 15 2004

EFFECTIVE DATE

DIRECTOR OR DESIGNEE
DEPARTMENT OF NATURAL RESOURCES

122004-007 2003-04-113

City Utilities of Springfield

P.O. Box 551, Springfield, MO 65801

City Utilities of Springfield - Southwest Power Station

5050 West FR 164, Springfield, MO 65619

Greene County, S7, T28N, R22W

Installation of a pulverized coal fired boiler with a nominal net electric output of 275 megawatts (2,724 million British Thermal Units per hour) and associated material handling equipment. This review was conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*.

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."

City Utilities of Springfield - Southwest Power Station
Greene County, S7, T28N, R22W

1. Operational Limitations
   - A. In the event that natural gas will be combusted in the pulverized coal (PC) fired boiler Number 2 (Emission Point E100) for purpose other than startup, flame stabilization, or emissions testing, City Utilities shall:
     1) Notify, and coordinate with, the Air Pollution Control Program prior to any planned emissions testing.
     2) Submit an Ambient Air Quality Analysis to the Air Pollution Control Program for all scenarios in which natural gas will be combusted, except for cases in which the sole purpose is for emissions testing.
     3) Receive prior approval from the Air Pollution Control Program based upon the Ambient Air Quality Analysis results before combusting natural gas for any purpose other than startup or flame stabilization.

   - B. If City Utilities receives written approval from the Air Pollution Control Program to burn natural gas in the PC boiler Number 2 (Emission Point E100), then :
     1) City Utilities shall not combust natural gas as the primary fuel in the pulverized coal boiler for more than 6,000 hours in any consecutive 12-month period.
     2) City Utilities shall not operate the boiler at loads greater than 60 percent when combusting natural gas as the primary fuel.

   - C. The sulfur content of the natural gas combusted in the PC boiler Number 2 (Emission Point E100) shall not exceed 0.05 percent by weight.

   - D. City Utilities shall operate only one (1) of the underground conveying systems (Emission Point E06) at any given time in which coal is conveyed from the storage pile to the boiler.

   - E. City Utilities shall not unload from railcars (Emission Points E01 and E120) more than 36,000 tons of coal in any 24-hour period.

SPECIAL CONDITIONS:

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

F. Restriction of Public Access – Fencing or Physical Barrier to Restrict Public Access to Property

1) City Utilities shall preclude all public access to property, according to U.S. EPA's definitions of ambient air (40 CFR 50.1(e)) and later related EPA determinations, which were excluded from the air quality analyses. A map showing the property boundary (precluded areas) is attached as Figure 1 and incorporated by reference.

2) City Utilities shall complete construction of the physical barrier to enclose the area prior to commencing operation of the pulverized coal-fired boiler (Emission Point E100).

G. City Utilities shall limit the truck traffic carrying fly ash to the landfill on haul road (Emission Point E12) to no more than 48 trips per 24-hour period.

H. City Utilities shall not operate the following existing emission points once the new PC boiler Number 2 (Emissions Point E100) becomes fully operational. A revised Ambient Air Quality Analysis must be submitted to the Air Pollution Control Program, which incorporates these emission points, before they may be operated.

Emission Point ID	Emission Point Description
E03	Primary crusher
E10	Pugmill
E11	Truck loading
E28	Unpaved haul road
E33	Limestone truck unloading
E34	Limestone storage pile
E35	Limestone transfer conveyor
E36	Limestone Preparation

2. Emission Limitations

Except during periods of startup, shutdown, or malfunction (as defined by 10 CSR 10-6.020(2)(M)4), City Utilities shall limit the following pollutant's emissions from the PC boiler Number 2 (Emission Point E100) when burning coal to:

A. Nitrogen Oxides (NO_X) to 0.08 pounds per million British Thermal Units (lbs/mmBtu) on a 30 day rolling average.

B. Sulfur Oxides (SO_2) to 0.095 lbs/mmBtu on a 30 day rolling average.

C. SO_2 emissions may not exceed an average of 490.5 lb/hr in any rolling 24-hour period, subject to the following:

SPECIAL CONDITIONS:

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

1) Each rolling 24-hour period may have a maximum of one discrete 3-hour period in which average SO_2 emissions exceed 490.5 lbs/hr.
2) For that 3-hour block of time, the SO_2 emissions may not exceed 6,785 lbs.

D. Carbon Monoxide (CO) to 0.16 lbs/mmBtu on a 30 day rolling average.

E. CO emissions to 436 lbs/hr.

F. Volatile Organic Compounds (VOCs) to 0.0036 lbs/mmBtu.

G. Particulate Matter Less Than Ten Microns in Aerodynamic diameter (PM_{10}) to 0.018 lbs/mmBtu.

H. Sulfuric Acid Mist (H_2SO_4) to 1.84 X 10^{-4} lbs/mmBtu.

I. H_2SO_4 emissions may not exceed an average of 0.74 lbs/hr in any rolling 24-hour period, subject to the following:
   1) Each rolling 24-hour period may have a maximum of one discrete 3-hour period in which average SO_2 emissions exceed 0.74 lb/hr.
   2) For that 3-hour block of time, the SO_2 emissions may not exceed 10.22 lbs.

J. Mercury (Hg) to 7.5 X 10^{-6} lbs/mmBtu.

K. Lead (Pb) to 2.56 X 10^{-5} lbs/mmBtu.

L. Hydrogen Chloride (HCl) to 0.00073 lbs/mmBtu.

M. Hydrogen Fluoride (HF) to 0.00037 lbs/mmBtu.

3. Best Available Control Technology (BACT)
   A. PC boiler Number 2 (Emission Point E100)
      1) City Utilities shall control NO_X emissions by using selective catalytic reduction (SCR).
      2) City Utilities shall control SO_2 emissions by using dry flue gas desulfurization (dry FGD).
      3) City Utilities shall control PM_{10} emissions by using a baghouse.
      4) City Utilities shall control volatile organic compounds (VOCs) emissions through the use of good combustion practices.
      5) City Utilities shall control carbon monoxide (CO) emissions through the use of good combustion practices.

SPECIAL CONDITIONS:

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

B. PM_{10} Emissions Sources

Emission Point ID	Emission Point Description	BACT
E01	Railcar unloading of coal	Enclosure to baghouse
E02	Conveyor transfer to main stacker	Water spray
E04	Stack drop point onto active coal pile	Water spray carryover and telescoping chute
E05	External Coal Storage Pile – Vehicle Activity Area	Watering or Chemical Surfactant
E06	Active coal transfer to Underground Conveyor	baghouse
E12	Haul road to landfill– unpaved	Watering or Chemical Surfactant
E12	Haul road to landfill– paved	Pavement
E74	Landfill haul road – unpaved	Watering
E101	Conveyor transfer to tripper deck	Enclosure to baghouse
E102	Conveyor transfer to mills (Note 1)	Enclosure to baghouse
E103	Coal mills operations (Note 1)	Enclosure to baghouse
E104	Conveyor transfer to storage silos	Enclosure to baghouse
E105	Recycle ash to FGD system	Wet collector
E106	Baghouse hopper to collecting conveyors transfer point	Enclosure to baghouse
E107	Waste powder silo Number 1	Enclosure to baghouse
E108	Waste powder silo Number 2	Enclosure to baghouse
E109	Conditioning of ash for landfill	Wet collector
E110	Waste powder to ash truck transfer point	Enclosure to baghouse
E112	Bottom ash transfer to conveyors	Wet material
E113	Conveyor transfer to silo	Wet material
E114	Ash truck transfer point – truck loading	Wet material
E115	Lime unloading	Enclosure to baghouse

SPECIAL CONDITIONS:

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

E116	Lime transfer to storage silos	Enclosure to baghouse
E117	Lime transfer to feed bins	Enclosure to baghouse
E118	Cooling tower	High efficiency drift eliminators – 0.001% drift
E119	Lime haul road	Pavement
E120	Railcar dump of raw coal	Enclosure to baghouse
E121	Conveyor transfer to drive tower	Enclosure to baghouse
E122	Drop point onto active coal pile	Water spray and telescoping chute
E123	Coal transfer to truck reclaim – James River	Enclosure to baghouse
E124	Conveyor transfer to truck loadout –James River	Enclosure to baghouse
E125	Coal transfer to underground conveyor	Enclosure to baghouse
E126	Coal haul road to James River	Pavement
E127	Powder activated carbon silo bin vent filter	Enclosure to baghouse
E128	Powder activated carbon haul road	Pavement

Note 1: In the event that City Utilities installs mills which are totally sealed so that there are no emissions from this source, the coal mills operation will not be considered an emission point and a baghouse will not be required.

4. Baghouses

A. All baghouses shall be operated and maintained in accordance with the manufacturer's specifications. The baghouse shall be equipped with a gauge or meter, which indicates pressure drop across the control device. These gauges or meters shall be located such that the Department of Natural Resources' employees may easily observe them. Replacement filters for the baghouses shall be kept on hand at all times. The bags shall be made of fibers appropriate for operating conditions expected to occur (i.e. temperature limits, acidic and alkali resistance, and abrasion resistance).

B. City Utilities shall monitor and record the operating pressure drop across the baghouses at least once every 24 hours. The operating pressure drop shall be maintained within the design conditions specified by the manufacturer's performance warranty.

SPECIAL CONDITIONS:

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

C. City Utilities shall maintain an operating and maintenance log for the baghouses which shall include the following:
   1) Incidents of malfunction, with impact on emissions, duration of event, probable cause, and corrective actions; and
   2) Maintenance activities, with inspection schedule, repair actions, and replacements, etc.

5. Haul Roads
   A. Paved Roads
      1) Maintenance and/or repair of the road surface will be conducted as necessary to ensure that the physical integrity of the pavement is adequate to achieve control of fugitive emissions from these roads.
      2) City Utilities shall periodically water, wash and/or otherwise clean all of the paved portions of the haul roads as necessary to achieve control of fugitive emissions from these roads.

   B. Unpaved Roads and Storagepile Vehicle Activity Area
      City Utilities shall control emissions from all unpaved haul roads by **either** documented watering or the application of chemical dust suppressant.
      1) Chemical Dust Suppressant
         a) The suppressant (such as magnesium chloride, calcium chloride, lignosulfonates, etc.) shall be applied in accordance with the manufacturer's suggested application rate and re-applied as necessary to achieve control of fugitive emissions from these areas.
         b) City Utilities shall keep records of the time, date, and the amount of material applied for each application of chemical dust suppressant agent on these areas. The records shall be kept on site for not less than five (5) years, and made available to Department of Natural Resources' personnel upon request.
      2) Documented Watering
         a) Documented watering will be applied in accordance with a recommended application rate of 100 gallons per day per 1,000 square feet of unpaved/untreated surface area of haul roads/vehicle active area as necessary to achieve control of fugitive emissions from these areas.
         b) City Utilities shall maintain a log that documents daily water applications. This log shall include, but is not limited to, date and volumes (e.g., number of tanker applications and/or total gallons used) of water application. The log shall also record

SPECIAL CONDITIONS:

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

rationale for not applying water on day(s) the areas are in use (e.g., meteorological situations, precipitation events, freezing, etc.).

c) Meteorological precipitation of any kind, (e.g. a quarter inch or more rainfall, sleet, snow, and/or freeze thaw conditions) which is sufficient in the amount or condition to achieve control of fugitive emissions from these areas while the areas are in use, may be substituted for documented water application until such time as conditions warrant applying documented watering.

d) Watering may also be suspended when the ground is frozen, during periods of freezing conditions when watering would be inadvisable for traffic safety reasons, or when there will be no traffic on the roads. City Utilities shall record a brief description of such events in the same log as the documented watering.

e) The records shall be kept on site for not less than five (5) years, and made available to Department of Natural Resources' personnel upon request.

6. Compliance Testing

A. Initial performance testing shall be conducted in order to verify compliance with the emission limitations for VOC, PM_{10}, Mercury, Lead, HCl, and HF specified in Special Conditions 2.F, 2.G, 2.J, 2.K, 2.L, and 2.M, respectively.

B. The stack tests shall be performed within 60 days of achieving the maximum production rate, but no later than 180 days after initial startup. Following the initial performance testing, City Utilities shall conduct the stack testing required by condition 6.A every five (5) years.

C. The date on which performance tests are conducted must be pre-arranged with the Air Pollution Control Program a minimum of 30 days prior to the proposed test so that a pretest meeting may be arranged if necessary, and to assure that the test date is acceptable for an observer to be present. A completed Proposed Test Plan form (copy enclosed) may serve the purpose of notification and must be approved by the Air Pollution Control Program prior to conducting the required emission testing.

D. Two (2) copies of a written report of the performance test results shall be submitted to the Director of the Air Pollution Control Program within 30

SPECIAL CONDITIONS:

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

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 (1) sample run.

E. Within 90 days of completion of the initial compliance testing for HCl and HF required by Condition 6.A, City Utilities shall submit a parametric monitoring plan based upon the stack test results for HCl and HF to the Air Pollution Control Program for approval.

F. Prior to conducting the initial performance tests for mercury and lead, City Utilities shall sample the coal combusted in the PC boiler Number 2 (Emission Point E100) in order to determine the mercury and lead content of the coal.

7. Continuous Emission Monitoring System (CEMS)/Continuous Opacity Monitoring System (COMS) – PC boiler Number 2 (Emission Point E100)

A. City Utilities shall install and operate CEMS for NO_X and SO_2 along with COMS in accordance with 40 CFR Part 60, Subpart Da and 40 CFR Part 75.

B. Carbon monoxide

1) City Utilities shall install, calibrate, maintain, and operate a CEMS for measuring CO emissions discharged to the atmosphere and record the output of the system for purposes of showing compliance with the CO emission limits of this permit.
2) The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 4A (PS4A) and Performance Specification 6 (PS6) requirements.
3) The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a quarterly notice to the Department with the dates of the quarterly cylinder gas audits and annual relative accuracy test audit.

C. Compliance with all non-NSPS CO, NO_X, and SO_2 emissions limits of this permit shall be demonstrated through the use of the required CEMS. City Utlities shall use the procedures describe in 40 CFR §75.32 to determine monitor availability.

1) The CEMS required by this permit shall be operated and data recorded during all periods of operation except for CEMS breakdown and repairs. Data will be recorded during calibration

SPECIAL CONDITIONS:

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

checks and zero and span adjustments.

2) The 1-hour average CO, NO_X, and SO_2 emission rates measured by the CEMS required by this permit shall be used to calculate compliance with the emission standards of this permit. At least 2 data points must be used to calculate each 1-hour average.

3) For each hour of missing SO_2 emissions data, City Utilities shall substitute data by:

   a) If the monitor data availability is equal to or greater than 95%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

      (1) For the missing data period less than or equal to 24 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour and the hour after the missing data period.

      (2) For a missing data period greater than 24 hours, substitute the greater of:

         (a) The 90^{th} percentile hourly concentration recorded by a pollutant concentration monitor during the pervious 720 quality-assured monitor operating hours; or

         (b) The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

   b) If the monitor data availability is at least 90% but less that 95%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

      (1) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

      (2) For the missing data period of more than 8 hours, substitute the greater of;

         (a) The 95^{th} percentile hourly pollutant concentration recorded by a pollutant concentration monitor during the previous 720

SPECIAL CONDITIONS:

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

quality-assured monitor operating hours; or

(b) The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

c) If the monitor data availability is less than 90%, the owner or operator shall obtain actual emission data by an alternate testing or monitoring method approved by the Department.

4) For each hour of missing NO_X (or CO) emissions data, City Utilities shall substitute data by:

a) Whenever the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(1) For a missing data period less than or equal to 24 hours, substitute, as applicable, for each missing hour, the arithmetic average of the flow rates or NO_X emission rates or NO_X (or CO) concentrations recorded by a monitoring system during the previous 2,160 quality- assured monitor operating hours at the corresponding unit load range or operational bin as determined using the procedure in Appendix C to 40 CFR Part 75.

(2) For a missing data period greater than 24 hours, substitute as applicable, for each missing hour, the greater of:

(a) The 90th percentile hourly flow rate or the 90th percentile NO_X (or CO) emission rate or the 90th percentile NO_X (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75; or

(b) The 90th percentile hourly flow rate or the 90th percentile NO_X (or CO) emission rate or the 90th percentile NO_X (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load

SPECIAL CONDITIONS:

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

range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75; or

(c) The average of the recorded hourly flow rates, NO_X (or CO) emission rates or NO_X (or CO) concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

b) Whenever the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(1) For a missing data period of less than or equal to 8 hours, substitute, as applicable, the arithmetic average hourly flow rate or NO_X (or CO) emission rate or NO_X (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75.

(2) For a missing date period greater than 8 hours, substitute, as applicable, for each missing hour, the greater of:

(a) The 95th percentile hourly flow rate or the 95th percentile NO_X (or CO) emission rate or the 95th percentile NO_X (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75; or

(b) The average of the hourly flow rates, NO_X (or CO) emission rates or NO_X (or CO) concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

(c) If the monitor availability is less than 90%, the owner or operator shall obtain actual emission data by an alternative testing or monitoring method approved by the Department.

SPECIAL CONDITIONS:

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

8. Record Keeping

A. City Utilities shall maintain an operational log, which shall detail each startup, shutdown, and malfunction of the PC boiler Number 2 (Emission Point E100).

B. City Utilities shall maintain inspection, maintenance, and repair log(s) for the PC boiler Number 2 (Emission Point E100) system

C. City Utilities shall maintain records demonstrating compliance with the NO_X, SO_2, CO, and opacity limits found in Special Conditions 2.A through 2.E using CEMS data outlined in Special Condition 7.

D. City Utilities shall develop a correlation between the SO_2 emissions from the PC boiler Number 2 (Emission Point E100) and the boiler's H_2SO_4 emissions. This correlation will be used to show compliance with Special Condition Numbers 2.H and 2.I.

E. City Utilities shall maintain records, based upon an approved parametric monitoring plan required by special condition 6.E, demonstrating compliance with the HCl and HF limits found in Special Conditions 2.L and 2.M.

F. City Utilities shall, upon approval from the Air Pollution Control Program to burn natural gas for purposes other than startup and flame stabilization, maintain a log detailing all occasions in which natural gas is used for purposes other than startup and flame stabilization of the PC boiler Number 2 (Emission Point E100). The log will, at a minimum, record the dates natural gas is used as the primary fuel, the reason for the switch from coal to natural gas, the percent load the boiler was operated, and the daily amount of natural gas combusted in the boiler.

G. At least once every year, after commencement of operation, City Utilities shall obtain from the fuel vendors or conduct their own fuel analysis to evaluate the typical sulfur content weight percent for natural gas.

H. City Utilities shall, upon approval from the Air Pollution Control Program to burn natural gas for purposes other than startup and flame stabilization, keep monthly, and the sum of the most recent 12-months records that are adequate to determine compliance with Special Condition Number 1.B.

SPECIAL CONDITIONS:

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

I. City Utilities shall maintain records of the railcar unloading operations (Emission Point E01 and E120). The records will at a minimum detail the dates coal is unloaded and the amount of coal unloaded each day.

J. City Utilities shall maintain records of the number trucks carrying fly ash to the landfill on the unpaved haul road (Emission Point E12) in order to demonstrate compliance with Special Condition Number 1.G.

K. City Utilities shall maintain all records required by this permit for not less than five (5) years and shall make them available immediately to any Missouri Department of Natural Resources' personnel upon request.

9. Reporting

A. City Utilities shall report to the Air Pollution Control Program's Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten (10) days after the day in which the records of Special Condition 8.C, 8.D, or 8.E show that the source exceeded the NO_X, SO_2, CO, H_2SO_4, HCl, or HF limits of found in Special Conditions 2.A through 2.E, 2.H, 2.I, 2.M, or 2.N.

B. City Utilities shall report to the Air Pollution Control Program's Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten (10) days after which performance testing, required by Special Condition 6, has been performed and the results indicate non-compliance with any special conditions of this permit. The notification shall include corrected potential emissions calculations based upon the performance test results.

C. City Utilities shall submit a case-by-case MACT analysis for the PC boiler Number 2 (Emission Point E100) to the Air Pollution Control Program's Permit Section, P.O. Box 176, Jefferson City, MO 65102, no later than 60 days after which performance testing, required by Special Condition 6, has been performed and the results demonstrate that the potential emissions of any single HAP exceeds 10.0 tons per year or the potential emissions of all HAPs combined exceed 25.0 tons per year,

10. Monitoring

A. City Utilities shall conduct post construction ambient monitoring for SO_2 for a period no less than one (1) year after the PC boiler Number 2 (Emission Point E100) is fully operational. Monitoring may be discontinued upon written request and approval from the Air Pollution Control Program's Director.

SPECIAL CONDITIONS:

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

B. The monitoring shall be conducted under an approved Quality Assurance Project Plan at sites approved by the Air Pollution Control Program.

C. The Quality Assurance Project Plan shall be submitted to the Air Pollution Control Program within a year from the date of issuance of this permit.

REVIEW OF APPLICATION FOR AUTHORITY TO CONSTRUCT AND OPERATE
SECTION (8) REVIEW
Project Number: 2003-04-113
Installation ID Number: 077-0039
Permit Number:

City Utilities of Springfield - Southwest Power Station
5050 West FR 164
Springfield, MO 65619

Complete: April 27, 2004
Reviewed: May 3, 2004

Parent Company:
City Utilities of Springfield
P.O. Box 551
Springfield, MO 65801

Greene County, S7, T28N, R22W

REVIEW SUMMARY

- City Utilities of Springfield has applied to install a pulverized coal fired boiler with a nominal net electric output of 275 megawatts (2,724 million British Thermal Units per hour) and associated material handling equipment at its existing Southwest Power Station.

- Hazardous Air Pollutant (HAP) emissions are expected from the proposed equipment. The primary HAPs of concern are mercury, lead, hydrogen chloride, and hydrogen fluoride. Potential HAP emissions were calculated to be below 10.0 tons per year for any single HAP or 25.0 tons per year for all HAPs combined. City Utilities is required to conduct stack testing to verify mercury, lead, hydrogen chloride, and hydrogen fluoride in order to verify the emissions factors used in the application.

- 40 CFR Part 60 Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978* is applicable to the new pulverized coal fired boiler (Emission Point E100). 40 CFR Part 60 Subpart Y, *Standards of Performance for Coal Preparation Plants* applies to the coal processing and conveying equipment (including the crushers), coal storage systems, and coal transfer and loading systems.

- None of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) or currently promulgated Maximum Achievable Control Technology (MACT) regulations apply to the proposed equipment.

- Potential HAP emissions were calculated to be less than 10.0 tons per year for any one HAP and less than 25.0 tons per year for all HAPs combined. Thus, City Utilities was not required to conduct a Section (9) review (case-by-case MACT determination) as required by 10 CSR 10-6.060(9), *Hazardous Air Pollutant Permits*. In the event that the stack test results demonstrate that the potential emissions of

any single HAP exceeds 10.0 tons per year or the potential emissions of all HAPs combined exceed 25.0 tons per year, City Utilities will have to submit a case-by-case MACT analysis for the new pulverized coal fired boiler.

- This review was conducted in accordance with Section (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*. This project is being reviewed as a major modification to CU's existing Southwest Power Station. Potential emissions of SO_X, CO, NO_X, PM_{10}, and VOC are above significant levels (i.e. de minimis levels).

- The Best Available Control Technology (BACT) requirements apply to the proposed equipment. The new pulverized coal fired boiler's NO_X emissions will be 0.08 lb/mmBtu, which will be achieved through the use of combustion controls and selective catalytic reduction (SCR). The boiler's SO_2 emissions will be controlled using dry flue gas desulfurization (FGD) and will be emitted at a rate of 0.095 lbs/mmBtu. PM_{10} emissions from the boiler will be conditioned to 0.018 lb/mmBtu, which shall be achieved through the use of a baghouse. CO and VOC emissions will be controlled by means of good combustion practices and their emission rates will be 0.16 lb/mmBtu and 0.0036 lb/mmBtu, respectively.

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

- This installation is on the List of Named Installations [10 CSR 10-6.020(3)(B), Table 2] Number 21. Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input. Therefore, the major source threshold for all criteria pollutants is 100 tons per year.

- Air quality modeling for this project was performed to determine the ambient impact of those pollutants that will be emitted in significant amounts (NO_X, PM_{10}, SO_2, CO, and VOC). Based upon the model reviewed by the Air Pollution Control Program staff, the study submitted by City Utilities is complete and demonstrates that City Utilities will not contribute to any violation of the National Ambient Air Quality Standards (NAAQS) or available increment.

- Based on the SO_2 National Ambient Air Quality Standards (NAAQS) and significance analysis, a post construction monitoring exercise is necessary to ensure compliance with the SO_2 NAAQS. Continuous Emission Monitoring Systems (CEMS) are required on the new pulverized coal fired boiler (Emission Point E100) to demonstrate compliance with NO_X, SO_2, and CO emission limits.

- Emissions testing for PM_{10}, VOC, sulfuric acid mist (H_2SO_4), mercury, lead, hydrogen chloride, and hydrogen fluoride will be required as specified in the special conditions of this permit.

- Approval of this permit is recommended with special conditions.

INSTALLATION DESCRIPTION

City Utilities of Springfield has applied for the authority to install a 275 MW pulverized coal boiler and associated material handling equipment at their existing Southwest Power Station (Installation ID Number 077-0039) located in Greene County. The existing installation has one 1,810 mmBtu/hr boiler and two twin-pac turbine generators. The boiler was installed in 1976 and is capable of combusting coal, pipeline grade natural gas, and fuel oil number 2. An electrostatic precipitator and wet limestone scrubber control emissions from this unit. The twin-pac turbine generators are 52 MW units capable of combusting pipeline grade natural gas and fuel oil number 2. The turbines were manufactured in 1972 but not installed until 1982. The existing installation has received a Part 70 Operating Permit (Permit Number OP2000-129) from the Air Pollution Control Program.

PROJECT DESCRIPTION

City Utilities of Springfield has reviewed their existing power production assets, known contracts to supply power, and the growth in demand for electrical energy and has determined through this comprehensive review that they will need to add additional baseload generation capabilities. Once this determination was made, City Utilities began to look at a variety of technologies that were capable of meeting its future energy demands. The different types of technology that City Utilities compared were subcritical pulverized coal, supercritical pulverized coal, atmospheric fluidized bed combustion, pressurized fluidized bed combustion, integrated gasification combined-cycle (IGCC), and renewable energy sources. In comparing these technologies, City Utilities compared availability, reliability, overall emissions, and finally costs of each of these technologies.

City Utilities looked at energy sources such as wind and fuel cells when examining renewable energy. It was determined that these technologies were not viable options in meeting City Utilities baseload energy needs at this time. However, City Utilities has stated that they will continue to look for ways to utilize renewable energy.

IGCC technology produces a low calorific value synthetic natural gas (syngas) from coal or solid waste to be fired in a combined-cycle turbine or utility boiler. IGCC is a developing technology, which is utilized by a handful of plants in the United States. Most of those plants have received funding from the U.S. Department of Energy. A review of the small number of existing IGCC projects indicates that IGCC emission rates are similar to those achieved by new subcritical pulverized coal boilers with add-on controls. When examining the operating experience of existing IGCC plants, City Utilities determined that the availability and reliability of IGCC plants fall short of that which is needed for a baseload unit.

After completing their review and comparing the different technologies, City Utilities decided that a subcritical pulverized coal boiler provided the best combination of availability, reliability, ability to follow load demands, and the lowest cost. When

comparing the emissions of a subcritical pulverized coal boiler (with add-on NO_X, SO_2, and PM_{10} controls) with the other technologies recently permitted, City Utilities determined that the emission rates were in the same range.

After deciding upon the type of technology to use, City Utilities of Springfield applied for the authority to install a new pulverized coal-fired boiler (SWPS Unit 2). The new boiler will provide steam for a steam turbine generator with a nominal net power output of 275 MW (2,724 mmBtu/hr). Low-NO_X burners in conjunction with SCR will be used to control the boiler's NO_X emissions. PM_{10} emissions from the boiler will be controlled by means of a baghouse. The baghouse will also aid in controlling inorganic HAPs (metals). A dry FGD, using lime as the reagent, will be installed to control SO_2 emissions. Good combustion practices will control CO and VOC emissions.

An increase in emissions from existing material handling equipment/operations will result due to the installation of the new boiler. The increase would be associated with the maximum design capacity of the new boiler. The boiler will be fired by low-sulfur western subbituminous coal at a maximum rate of 170 tons per hour. The coal is delivered to the Southwest Power Station via bottom dump railcars. Each train carries up to 18,000 tons of coal. Approximately one (1) train is processed every 48 hours.

Coal is unloaded from the railcars into hoppers. Emissions from the railcar unloading will be controlled using a fabric filter. The coal is then conveyed from the hoppers to a transfer tower and then to a stockout conveyor. A water spray is applied to the coal in the transfer tower and at the head end of the stockout conveyor. The stockout conveyor discharges the coal onto the storage pile with a telescoping chute.

Conveyors, originating beneath the storage pile, will be used to convey the coal from the storage pile to new in-plant storage silos. The coal is then conveyed to a new milling system. Each of these transfer points and operations will be closed and vented to a fabric filter.

To provide for fuel during interrupted or delayed deliveries, Southwest Power Station will maintain coal in a "dead" storage pile. Coal is transferred from the dead storage pile to the underground conveyors via mobile equipment into in-ground hoppers. A fabric filter will be used to control emissions from these emission points.

The coal that will be used in SWPS Unit 2 will have an ash content up to approximately 6.9 percent. Approximately 80 percent of the total ash becomes entrained in the gas stream and the remaining 20 percent is removed as bottom ash. SWPS Unit 2 is expected to generate approximately 13.8 tons per hour of fly ash and bottom ash. In addition to fly ash, the gas stream contains lime particles that are entrained as a result of lime injected into the gas stream as part of the FGD system. The entrained particles are removed from the gas stream by a baghouse. The captured material is then pneumatically transferred from the baghouse hoppers to the storage silos. The pneumatic transfer of the waste material will be controlled using a fabric filter. Two (2) new storage silos will be added in order to accommodate the material from SWPS Unit 2.

Due to the lime particles mixed with the fly ash, the material is expected to have little commercial value. Thus, the waste material collected in the storage silos will either be slurried and recycled to the absorption system or conditioned and transferred to trucks for hauling to the existing on-site landfill. The fly ash to be recycled to the absorber system is mixed with water in a tank to produce a slurry. Particulate emissions from the tank will be controlled with a wet collector.

The ash material sent to the landfill will be conditioned in a pug mill (or similar device). The emissions from the conditioning process are controlled with a wet collector. Once conditioned, the material is loaded onto trucks and transported to the existing on-site landfill using paved and unpaved haul roads. The material will be unloaded from the trucks by open drop.

The lime used as a part of the FGD system will be transported to the Southwest Power Station via trucks and pneumatically transferred to storage silos and then from the storage silos to the slakers. The truck unloading and pneumatic transfers will be enclosed and vented to a baghouse.

Potential HAP emissions from the proposed project were calculated to be less than 10.0 tons per year for any one HAP and less than 25.0 tons per year for all HAPs combined. Based upon these calculations, City Utilities was not subject to a case-by-case MACT analysis. However, in light of pending mercury regulations, City Utilities decided to include as a part of this project the emissions associated with a potential mercury control system. City Utilities is anticipating controlling mercury emissions by means of injecting powdered activated carbon. However, a final decision as to the exact method of mercury control has not been made. City Utilities does plan on installing some type of mercury control, but is holding off making a final decision until a later date so that the most effective system of mercury control that has been shown to be compatible with the NO_X, PM, and SO_X pollution control technologies can be determined. If the mercury control is not powdered activated carbon, then it will be at least as effective. The reason City Utilities included the emission points associated with the powdered activated carbon, which is the current plan to control mercury, is so that modeling will not have to be done again.

The powdered activated carbon is a fine talc-like material that will be brought on site via trucks and pneumatically conveyed into storage silos. The transfer from the trucks to the silos will be controlled with a baghouse.

In addition to the new pulverize coal boiler and its associated equipment, City Utilities will also be adding a new coal unloading station that will allow the use of the existing rail access at the Southwest Power Station as an additional coal delivery point for their James River Station (077-0005). Coal would be delivered to the Southwest Power Station by rail and the transported by truck to James River if this option is exercised in the future.

EMISSIONS/CONTROLS EVALUATION

All of the criteria pollutants will be emitted from the new pulverized coal fired boiler (Emission Point E100) with the potential NO_X, SO_2, PM_{10}, CO, and VOC emissions greater than significance levels (i.e. greater than de minimis levels). HAP emissions are also expected from the operation of the boiler. Potential emissions of all pollutants were calculated based upon the operating scenario with the highest emission rate, assuming continuous operation (8760 hours annually), and a maximum heat input rate to the boiler of 2,724 mmBtu/hr

A BACT analysis was conducted on the boiler for NO_X, SO_2, PM_{10}, CO, and VOC. Combustion controls and SCR will be used to control NO_X emissions. A Dry FGD will be installed using lime as the reagent to control SO_2 emissions. A baghouse will be used to control PM_{10} emissions, while CO and VOC emissions will be minimized through the use of good combustion practices. Potential emissions of each of these pollutants were calculated based upon each pollutant's respective BACT emission rate limit. The NO_X, SO_2, and CO emission rate will be verified through the use of CEMS. The PM_{10} and VOC emission rates will be verified by stack testing.

Potential emissions of sulfuric acid (H_2SO_4), lead, and mercury from the boiler were based upon emission factors of 1.84×10^{-4} lb/mmBtu, 2.56×10^{-5} lb/mmBtu, and 7.5×10^{-6} lb/mmBtu, respectively. The emission rate of hydrogen chloride was determined using the chlorine content of the coal and assuming a control efficiency of 96 percent due the FGD system. The emission rate of the hydrogen fluoride was based upon AP-42 factors and a control efficiency of 96 percent due to the FGD system. All other HAP emissions were based upon EPA document AP-42, *Compilation of Air Pollution Emission Factors*, Fifth Edition, Section 1.1 *Bituminous and Subbituminous Coal Combustion* (9/98). Sulfuric acid, lead, mercury, hydrogen chloride, and hydrogen fluoride emission rates will be verified through stack testing.

The cooling tower will also emit PM_{10}. City Utilities intends to use treated effluent from a nearby wastewater treatment plant as the cooling water source. The cooling tower's potential PM_{10} emissions were calculated assuming a total dissolved solids concentration of 4,500 parts per million (ppm). The high efficiency drift eliminator will control drift to 0.001 percent, leaving a drift rate of approximately 1.50 gallons of water per minute lost from the cooling tower.

The transfer and handling operations of the coal, lime, and fly ash will result in PM_{10} emissions. Most of these emission points will be control through the use of a baghouse. A control efficiency of 99 percent was applied for the use of the baghouse. The coal loadout to the storage piles can not be controlled by means of a baghouse. Thus, water spray and a telescoping chute will control the coal loadout to the storage piles. Several of the emission points associated with the fly ash operations will also not be capable of being controlled by a baghouse. Emissions from these emission points will be controlled by means of a wet collector or by wetting the material.

The potential emissions of the rail car unloading were based upon a maximum of 36,000 tons of coal unloaded per day from Emission Points E01 and E120. Emissions from all other coal handling operations were based upon 170 tons of coal per hour, which correlates to the maximum heat input rate of the new pulverized coal fired boiler. All haul roads will be paved except for one small strip running from the edge of the landfill onto the landfill itself. Paving of the landfill haul road is not feasible in that the road changes as the landfill utilization changes. Emissions from the unpaved haul road will either be controlled through the application of chemical surfactant or documented watering. Emissions from the coal storage piles will be controlled through the use of chemical surfactant and/or water suppression. Potential emissions from the paved haul roads, unpaved haul roads, and storage piles were calculated based upon EPA document AP-42, *Compilation of Air Pollution Emission Factors*, Fifth Edition, Section 13.2.2 *Unpaved Roads* (9/98), Section 13.2.1 *Paved Roads* (10/02), and 13.2.4 *Aggregate Handling and Storage Piles (1/95).*

Table 1: Emissions Summary (tons per year)

Pollutant	**Regulatory *De Minimis* Levels**	**Existing Potential Emissions**	**Existing Actual Emissions (2003 EIQ)**	**Potential Emissions of the Application**
PM_{10}	15.0	major	276.7	243.6
SO_2	40.0	major	3,857.0	1,143
NO_X	40.0	major	2,425.9	954.4
VOC	40.0	major	17.3	43.0
CO	100.0	major	203.9	1,909
HAPs	10.0/25.0	major	37.41	22.8
H_2SO_4 mist	7.0	N/D	N/D	2.2
Lead	0.6	N/D	.01	0.31
Mercury	0.1	N/D	N/D	0.09
Hydrogen Chloride	10.0	N/D	N/D	8.84
Hydrogen Fluoride	10.0	N/D	N/D	4.47

*N/D = Not Determined

PERMIT RULE APPLICABILITY

Potential emissions of NO_X, SO_2, PM_{10}, CO, and VOC are greater than significance levels (i.e. greater than de minimis levels). Therefore, this review was conducted in accordance with Section (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required.* Compliance with this section of the rule means that the proposed sources will not interfere with the attainment or maintenance of ambient air quality standards, will not cause or contribute to ambient air concentrations in excess of any applicable maximum allowable increase as listed in 10 CSR 10-6.060, Subsection (11)(B), Table 1, over the baseline concentration in any attainment or unclassified area, will not violate any applicable emission control regulations or the Air Conservation Law.

APPLICABLE REQUIREMENTS

City Utilities of Springfield - Southwest Power Station 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.

- *Submission of Emission Data, Emission Fees and Process Information,* 10 CSR 10-6.110
  The emission fee is the amount established by the Missouri Air Conservation Commission annually under Missouri Air Law 643.079(1). Submission of an Emissions Inventory Questionnaire (EIQ) is required April 1 for the previous year's emissions.

- *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 10-4.070

- *Open Burning Restrictions*, 10 CSR 10-4.090

- *Start-Up, Shutdown and Malfunction Conditions*, 10 CSR 10-6.050

SPECIFIC REQUIREMENTS

- *Restriction of Emission of Sulfur Compounds,* 10 CSR 10-6.260

- *Restriction of Emission of Particulate Matter From Industrial Processes*, 10 CSR 10-6.400

- *Emission Limitations and Emissions Trading of Oxides of Nitrogen,* 10 CSR 10-6.350

- *New Source Performance Regulations*, 10 CSR 10-6.070 – *New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, 40 CFR Part 60, Subpart Da and for *Standards of Performance for Coal Preparation Plants*, 40 CFR Part 60, Subpart Y.

BACT ANALYSIS

Introduction

Any source subject to Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, Section (8) must conduct a Best Available Control Technology (BACT) analysis on any pollutant emitted in greater than de minimis levels. The BACT requirement is detailed in Section 165(a)(4) of the Clean Air Act, at 40 CFR 52.21 and 10 CSR 10-0.60(8)(B).

A BACT analysis is done on a case by case basis and is performed using a "top down" method. The following steps detail the top-down approach:

1. Identify all potential control technologies – must be a comprehensive list, it may include technology employed outside the United States and must include the Lowest Achievable Emission Rate (LAER) determinations.
2. Eliminate technically infeasible options – must be well documented and must preclude the successful use of the control option.
3. Rank remaining control technologies – based on control effectiveness, expected emission rate, expected emission reduction, energy impacts, environmental impacts, and economic impacts.
4. Evaluate the most effective controls – based on case by case consideration of energy, environmental, and economic impacts.
5. Select BACT

The pulverized coal fired boiler (Emission Point E100) and associated equipment are subject to Section (8) since the proposed project will have the potential to emit NO_X, SO_2, PM_{10}, CO, and VOC above significance levels. City Utilities prepared a BACT analysis for these pollutants based on the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database, vendor information, and previous permits for combustion turbines issued in the State of Missouri and elsewhere. The BACT determination must be at least as stringent as the NSPS for Electric Utility Steam Generating Units and Coal Preparation Equipment set forth in 40 CFR Part 60 Subparts Da and Y. The BACT analysis is summarized, by pollutant, below.

NO_X Control Technologies – Pulverized Coal Fired Boiler

Table 2 lists the control technologies City Utilities evaluated for this review (in order of control achieved) and the emission rates each control technology can attain.

Table 2: NO_X Control Technologies Considered

Control Technology	Emission Rate Achieved
SCR and Good Combustion Practices	0.08 lb/mmBtu
Low NO_X Burners/Overfired Air and SCR	0.15 lb/mmBtu
Low NO_X Burners and SCR	0.15 - 0.17 lb/mmBtu
SCR	0.15 – 0.17 lb/mmBtu
Low NO_X Burners with Flue Gas Recirculation	0.16 lb/mmBtu
Selective Non-catalytic Reduction (SNCR)	0.17 lb/mmBtu
Low NO_X Burners/Overfired Air and SNCR	0.17 lb/mmBtu

SCR

SCR is a post-combustion control technology in which the gas stream is passed through a catalyst bed in the presence of ammonia. The ammonia and NO_X react to form nitrogen and water. City Utilities proposed the installation of SCR and good combustion practices as BACT for NO_X from the pulverized coal fired boiler.

Selection of NO_X Control Technology for Pulverized Coal Fired Boiler
Since City Utilities proposed SCR with good combustion practices, which has the highest level of control for NO_X. No further evaluation of other control technologies was conducted.

The actual performance of an SCR system varies significantly depending on the volume of catalyst, SCR inlet NO_X level, operating temperature, age of the catalyst, flue gas distribution, and the ammonia injection rate. For SCR control, the difference between new and older equipment performance is substantial. SCR catalyst performance deteriorates over time due to normal deactivation and degradation of the catalyst surface. The SCR must be designed so that the emission limits at the end of the catalyst life are still being obtained. Based upon the limited operating history of boilers equipped with SCR equipment and which burn Powder River Basin (PRB) coal, it appears as if the PRB coal contributes to a decrease in the catalyst life. Based upon this information, the SCR catalyst would have to be replaced more frequently.

City Utilities conducted an economic evaluation if the emission limit was 0.07 lbs/mmBtu and the catalyst was replaced every 18 months and compared the results to that of an emission limit of 0.08 lbs/mmBtu and the catalyst replaced every three (3) years. The average cost per ton of NO_X removed for the 0.08 and 0.07 lbs/mmBtu cases, was determined to be $949 and $1,799, respectively. The incremental control cost increased substantially from $4,748/ton to $31,177/ton when comparing the emission scenarios of 0.08 lbs/mmBtu to 0.07 lbs/mmBtu.

It was determined that the BACT for NO_X from the pulverized coal fired boiler is good combustion practices along with SCR having a NO_X emission limit of 0.08 lbs/mmBtu on a 30-day rolling average. This decision was based in part upon the fact that there are no pulverized coal fired boilers currently operating, which have achieved an emission rate of 0.07 lbs/mmBtu over an extended period of time. Additional consideration was given to the increased cost associated with a 0.07 lbs/mmBtu limit and replacing the catalyst more frequently.

SO_2 Control Technologies – Pulverized Coal Fired Boiler

Table 3 lists the control technologies City Utilities evaluated for this review (in order of control achieved) and the emission rates each control technology can attain.

Table 3: SO_2 Control Technologies Considered

Control Technology	Percent SO_2 Reduction
Wet flue gas desulfurization (Wet FGD)	> 90%
Dry flue gas desulfurization (Dry FGD)	> 90%

Wet Flue Gas Desulfurization (Wet FGD)
Wet FGD is a well-established process for removing SO_2 emissions from flue gas. In wet FGD, the flue gas enters the spray tower or absorber where it is sprayed with an alkaline slurry. The preferred sorbents are limestone and lime. The calcium in the slurry reacts with the SO_2 in the flue gas to form calcium sulfite or calcium sulfate. The wet FGD systems normally consist of two stages. The first stage is the fly ash removal either by electrostatic precipitator (ESP) or a baghouse. The second state is the SO_2 removal. An emission rate of 0.10 lb/mmBtu for SO_2 can be accomplished through the use of wet FGD.

Dry Flue Gas Desulfurization (Dry FGD)
Dry FGD is also a well-established process for removing SO_2 emissions from flue gas. Dry FGD uses the same primary chemical reactions as a wet FGD system in which the flue gas contacts an alkaline slurry to remove SO_2 emissions. However, the quantity of water introduced to the flue gas in a dry FGD is limited so that the flue gas does not reach saturation temperatures. The dry FGD product and fly ash is then collected in the particulate control equipment (baghouse) located downstream of the FGD system along with the fly ash. Dry FGD can achieve an approximately 94 percent reduction for SO_2 emissions. However, the wet FGD could provide slightly lower SO_2 emissions than the dry FGD.

Selection of SO_2 Control Technology for Pulverized Coal Fired Boiler
It was determined that SO_2 BACT for the pulverized coal fired boiler would be dry FGD even though wet FGD can provide slightly lower SO_2 emissions. This decision was based upon environmental, economical, technical, and energy considerations.

A wet FGD system is less effective at controlling total particulates, PM_{10}, fine particulates, and HAPs than dry FGD. This is because the absorbers are located downstream of the particulate control equipment. Carryover from the wet FGD absorber's mist eliminator may contribute to increased fine particulate emissions. Dry FGD achieves greater control of sulfuric acid mist than does wet FGD.

A wet FGD system requires a greater amount of electric energy for operation than does a dry FGD. Power is required to operate pumps to recirculate the slurry to the absorber, limestone grinding, waste dewatering, and for fan capacity to overcome the FGD system pressure loss. The larger demand for energy directly correlates to increased cost and emissions due to the wet FGD.

A BACT SO_2 emission rate for the dry FGD was set at 0.12 lbs/mmBtu (See note at bottom of page) on a 30-day rolling average. City Utilities did conduct an evaluation on achieving an SO_2 emission rate of 0.10 lbs/mmBtu. As stated earlier, dry FGD can achieve SO_2 emissions reductions of up to 94 percent. Obtaining this high removal efficiency is dependent on good gas-to-liquid contact and also on how closely the absorber's outlet temperature approaches the adiabatic saturation temperature. Operating closer to the adiabatic saturation temperature allows higher SO_2 control efficiencies. However, if the outlet temperature from a spray dryer is too close to the saturation temperature operating problems such as build-up in the absorber modules, blinding of fabric filer bags, corrosion in the fabric filer and ductwork, and operating and maintenance problems with the fly ash handling system can occur.

Most operators of spray dryers have an established maintenance program to change out the atomizers for inspection, cleaning and repair on a regularly scheduled basis. It is not uncommon for the atomizers to be changed out at monthly intervals. However, it is also not uncommon for the spray dryer to be out of service for additional hours in a month due to unanticipated equipment problems and maintenance. A change-out of an atomizer takes approximately two to three hours to complete. During this two to three hour period, SO_2 emissions will be uncontrolled. Taking this into account, City Utilities developed several different scenarios in which the spray dryer was down for different lengths of time. The first scenario evaluated the case in which there was 10 hours of spray dryer outage during a 30-day averaging period. If the spray dryer was operated at a 94 percent control efficiency the remaining 710 hours of the averaging period, a 30-day rolling average of 0.107 lbs/mmBtu could be achieved.

The second scenario looked at the case in which the spray dryer was only out for three hours during a 30-day averaging period. If the spray dryer controlled SO_2 emissions at a rate of 94 percent the remaining hours of the averaging period, a control efficiency of 0.094 would be achieved.

A third scenario examined the situation in which the spray dryer was down for three hours during a 30-day averaging period and for the remaining 710 hours of the period SO_2 were controlled at 92 percent. This scenario would correlate to a 30-day average of 0.123 lbs/mmBtu.

A SO_2 emission rate was set at 0.12 lbs/mmBtu (See note at bottom of page) by examining each of these scenarios while taking into account the likelihood of the spray dryers being down for a period of time each month along with the problems that can arise with operate the system too close to the adiabatic saturation temperature. This emission rate falls within the range of other recently permitted coal fired boilers.

Note: Due to comments received on the draft permit, the emissions rate was changed to 0.095 lbs/mmBtu. Please see response to comments for more details.

PM_{10} Control Technologies – Pulverized Coal Fired Boiler

Table 4 lists the control technologies City Utilities evaluated for this review (in order of control achieved) and the emission rates each control technology can attain.

Table 4: PM_{10} Control Technologies Considered

Control Technology	Percent PM_{10} Reduction
Baghouse	99.9%
Electrostatic Precipitator (ESP)	>99%

Baghouse

Baghouses are a well-established technology in controlling particulate matter from flue gas. Filtering bags are suspended in a housing in which the flue gas passes through. Particulate matter in the flue gas collects on the bag's surface. Baghouses are capable of achieving a 99.9 percent reduction in PM_{10} emissions. In addition to controlling PM_{10} emissions, baghouses will control particulate HAP emissions. City Utilities proposed the installation of a baghouse to control PM_{10} emissions from the pulverized coal fired boiler.

Selection of PM_{10} Control Technology for Pulverized Coal Fired Boiler

Since City Utilities proposed the top control for PM_{10} emissions, no further evaluation of other controls was conducted. BACT for PM_{10} emissions from the pulverized fired coal boiler was determined to be a baghouse with an emission rate of 0.018 lbs/mmBtu on a 30-day rolling average. This emission limit is consistent with other recent BACT determinations for similar projects.

CO Control Technologies – Pulverized Coal Fired Boiler

Table 5 lists the possible control technologies (in no particular order) for CO emissions from the pulverized coal fired boiler.

Table 5: CO Control Technologies Considered

Control Technology
Catalytic Oxidation
$SCONO_X$
Good Combustion Practice

Catalytic Oxidation

Oxidation catalysts are a post-combustion technology used to oxidize CO to carbon dioxide (CO_2) without the introduction of additional chemicals. The activation energy for this reaction is lowered through the use of a catalyst and the oxidation then proceeds by utilizing excess air present in the turbine exhaust. An oxidation catalyst is usually precious metal (i.e. platinum) based, and operates in an optimal temperature range between 700˚F and 1,100˚F.

The use of oxidation catalysts with fuels containing sulfur can promote the oxidation of SO_2 to SO_3. The SO_3 can react with water or ambient ammonia in the exhaust to form H_2SO_4. The optimal temperature range for the performance of the oxidation catalyst would required the catalyst be installed upstream of the FGD system and fabric filter. The ash and trace elements in the exhaust stream would foul or destroy the catalyst. In addition, catalytic oxidation has never been applied to a coal-fired unit. Thus, the use of a catalytic oxidation system for the proposed pulverized coal fired boiler is not considered technically feasible.

$SCONO_X$

The $SCONO_X$ system uses an oxidation/absorption/regeneration cycle across a catalyst bed to achieve back end reductions of CO. The technology utilizes the same principles as catalytic oxidation for CO control. Thus, $SCONO_X$ is eliminated from further consideration for the same reasons as catalytic oxidation.

Good Combustion Practices

CO emissions are the result of incomplete combustion. However, reducing CO emissions can result in an increase of NO_X emissions. CO and NO_X emissions can be balanced through the use of good combustion practices. Good combustion practices include practices such as operating with higher flame temperatures, adequate combustion air, and proper air/fuel mixing.

Selection of CO Control Technology for Pulverized Coal Fired Boiler

As discussed above, the use of catalytic oxidation or $SCONO_X$ are not feasible control options for CO emissions resulting from a pulverized coal fired boiler. The remaining control technology for CO emissions is the implementation of good combustion practices. Thus, the utilization of good combustion practices with a CO emission limit of 0.16 lbs/mmBtu was determined to be BACT for CO from the pulverize coal fired boiler. This determination and associated emission rate is consistent with other recently permitted pulverized coal fired boilers.

Selection of VOC Control Technology for Pulverized Coal Fired Boiler

Like CO, VOC emissions are the result of incomplete combustion of the coal. The most efficient means of controlling VOC emissions is combustion. The boiler is essentially a combustion chamber, and as such, the proper operation of the boiler through the use of good combustion practices will promote complete combustion. Good combustion practices include extended residence time, proper mixing of air and fuel, and steady high temperatures in the combustion zone. Thus, the utilization of good combustion practices with a CO emission limit of 0.0036 lbs/mmBtu was determined to be BACT for VOC from the pulverize coal fired boiler. This determination and emission rate is consistent with other recently permitted pulverized coal fired boilers

PM_{10} Control Technologies – Cooling Tower

Particulate emissions occur from the cooling tower as a result of the total solids in the water being entrained in the air stream. These droplets of water are known as drift. The most efficient way to remove drift from cooling towers is by installing drift eliminators. Thus, BACT for PM_{10} from the cooling tower was determined to be high efficiency drift eliminators with a 0.001 percent drift.

PM_{10} Control Technologies – Haul Roads

BACT for all haul roads, with the exception of the landfill haul road, was determined to be the paving and periodically washing the roads. This represents the highest level of PM_{10} control, and as such no further evaluation was conducted for other control technologies.

The haul road running from the edge of the landfill onto the landfill itself will not be paved. Paving of the landfill haul road is not feasible in that the road changes as the landfill utilization changes. Thus, BACT for the landfill haul road was determined to be either the application of chemical surfactant or documented watering to achieve a control efficiency of 90 percent.

PM_{10} Control Technologies – Storage Piles

The size of the storage piles makes capture of particulate matter emissions from the storage piles by mechanical devices infeasible. Thus, it is not possible to control the storage pile emissions through the use of a baghouse. BACT for the storage pile was determined to be application of chemical surfactant or the use of water suppression.

PM_{10} Control Technologies – Coal Handling Operations

The only pollutant that will be emitted from the coal handling equipment is PM_{10}. The coal handling operations include the railcar unloading system, the transfer tower, coal unloading system to the storage pile, the underground coal loading system from the storage pile, the tripper house activities, and the coal milling operations.

All of the handling points, except the conveyor transfer to the main stacker and the unloading point onto the storage pile, can easily be enclosed and vented to a baghouse. This represents the highest level of control for these emission points, and as such is considered BACT.

Since the conveyor transfer to the main stacker and the unloading point onto the storage pile can not be enclosed, it is not possible to vent the emissions from these points to a baghouse. Thus, BACT was determined to be the use of water spray for the conveyor transfer to the main stacker and the use of water spray in conjunction with a telescoping chute for the unloading point onto the storage pile.

PM_{10} Control Technologies – Lime Handling Operations

The lime handling operations consist of lime handling, storage, and preparation equipment which will be necessary to supply the lime to the FGD system. Lime will be delivered to the plant via trucks, unloaded, and then pneumatically transferred to storage silos. The lime will then be pneumatically transferred from the storage silos to the slakers. BACT for the lime handling, transfer, and preparations points was determined to be the use of baghouses.

PM_{10} Control Technologies – Fly Ash Handling Operations

Fly ash collected in the baghouse will be pneumatically transferred to storage silos and will be controlled through the use of a baghouse. Fly ash collected in the storage silos will either be slurried and recycled to the absorption system or conditioned and transferred to trucks for hauling to the on-site landfill. Both of these operations will be controlled through the use of a wet collector.

AMBIENT AIR QUALITY IMPACT ANALYSIS

City Utilities submitted a Class I and Class II Ambient Air Quality Impact Analysis (AAQIA). The Class I AAQIA was for Hercules Glades, Mingo Wildlife Refuge, and Upper Buffalo Wilderness Area. Based upon the model reviewed by the Air Pollution Control Program staff, the study submitted by City Utilities is complete and demonstrates that City Utilities will not contribute to any violation of the National Ambient Air Quality Standards (NAAQS) or available increment. For a more thorough discussion of the modeling methodology used and the results, please refer to the attached memorandums entitled, *Ambient Air Quality Impact Analysis (AAQIA) for City Utilities of Springfield – Southwest Power Station, Prevention of Significant Deterioration (PSD) Modeling* and *Class I Ambient Air Quality Impact Analysis (AAQIA) for City Utilities of Springfield, Southwest Power Station April Submittal.*

STAFF RECOMMENDATION

On the basis of this review conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, I recommend this permit be granted with special conditions.

Kendall Hale
Environmental Engineer

Date

PERMIT DOCUMENTS

The following documents are incorporated by reference into this permit:

- The Application for Authority to Construct form, dated April 2, 2003, received April 22, 2003, designating City Utilities of Springfield as the owner and operator of the installation.
- U.S. EPA document AP-42, *Compilation of Air Pollutant Emission Factors*, Fifth Edition.
- Southwest Regional Office Site Survey, dated May 12, 2003.
- Class II Air Dispersion Refined Modeling Analysis, dated March 2004.
- Class I Air Quality Modeling Study for the Proposed 275-Megawatt Coal-fired Generation Facility, dated April 2004
- Document submitted by City Utilities of Springfield entitled *BACT Emission Limitations for PC Boilers Firing Western Subbituminous Coal*
- Document submitted by City Utilities of Springfield entitled *Technology Assessment Supplement*
- E-mail received from Ethan Begg, dated May 3, 2004, providing additional BACT information.

Attachment to Permit Number 122004-007

Comments and Responses on City Utilities of Springfield's Prevention of Significant Deterioration New Source Review Permit Application

This document responds to comments made to the PSD permit application. Comments have been summarized or paraphrased for the sake of clarity. The numbers of Special Conditions in the comments may have changed. The numbers referenced in the response reflect the final Special Condition numbering.

The following comments were submitted to the Air Pollution Control Program by the Federal Land Manager.

Comment:
Our analysis shows that the proposed emission limits in the permit are consistent with the emissions used in the dispersion modeling studies for impacts to Class I areas managed by USDA –FS. As such, we agree with the proposed emission limits, provided that comments expressed elsewhere in this letter are addressed. If any changes to the proposed emissions limits are considered, please advise USDA-FS before the final permit is issued so we may assess how these changes could affect impacts to the Class I areas of interest.

City Utilities' Response:
No response.

Air Pollution Control Program's Response:
No emission limitations were changed which resulted in higher emissions of any pollutant.

Comment:
Our review of the Class I area modeling indicates that the Class I PSD increments for Upper Buffalo may be exceeded by existing increment consuming emissions. However, it appears that the proposed City Utilities source does not contribute significantly to the predicted Class I increment violation and as such, the proposed permit is unaffected by the predicted violation. USDA-FS agrees with this conclusion. However, the predicted Class I increment violation at Upper Buffalo is a serious issue that must be promptly addressed by the appropriate regulatory authority. USDA-FS requests that the State of Missouri provide documentation of the predicted Class I increment violations at Upper Buffalo to the appropriate authorities in the State of Arkansas so they can investigate the predicted violation and implement any corrective actions necessary to eliminate the predicted Class I increment violation.

City Utilities Response:
No response.

Air Pollution Control Program's Response:
The Air Program agrees to this request.

Comment:
Our review of the visibility modeling completed to date for impacts at Hercules-Glades and Upper Buffalo does not yet convince us that the proposed emissions will not adversely impact visibility at these areas. Modeling performed by both the applicant and by the State of Missouri show that Hercules-Glades in particular may experience more than a 10% change in light extinction. Under the FLAG guidance, this is considered a potential adverse impact to visibility.

The primary difference between the applicant's modeling analysis and that performed by the State of Missouri is with the background ammonia concentration used in the analysis. The applicant selected 0.5 ppb for background ammonia based on the recommended value for "forested" areas in the Interagency Workshop on Air Quality Modeling (IWAQM) guidance. The State of Missouri modeling used 5.0 ppb for the background ammonia value. The USDA-FS had recommended a background ammonia level of 4.3 ppb in our earlier comments on the Class I modeling protocol, which the applicant has apparently elected to ignore. Our recommendation was developed using the weighted average of the recommended IWAQM values based on land use patterns for probably trajectories of plume transport to the Class I areas of interest. We believe the higher background ammonia value we recommended is also supported by available data from the CENRAP Inter-RPO Ammonia Monitoring Study, which has documented a 3.4 ppb ammonia background value for a site near Pleasant Green, MO for March 2004. Because the State of Missouri CALPUFF modeling used a value closer to the USDA-FS recommended background ammonia value, we are placing more reliance of the State of Missouri CALPUFF modeling analysis in our evaluation.

The State of Missouri CALPUFF modeling for Hercules-Glades predicted seven days over a three-year period with a change in light extinction of five percent or more and three days over three years with a change in light extinction of ten percent or more. this converts to 1.0 days/year with more than a 10 percent change and 2.3 days/year with more than a 5 percent change. At Upper Buffalo, there were eight days over three years or 2.7 days/year with more than five percent change in light extinction, but zero days over 10 percent change. The above values were modeled using the worse-case 24-hour average SO_2 emission rate of 0.18 lb/MMBtu. USDA-FS recognizes that these SO_2 emissions

cannot occur continuously given the proposed 30-day rolling average SO_2 limit of 0.12 lb/MMBtu. At most, the 0.18 lb/MMBtu SO_2 emission can occur two out of every three days; but in all likelihood, the frequency of SO_2 emission approaching 0.18 lb/MMBtu will be considerably less. The predicted frequency of any potential impact to visibility in Class I areas is an important consideration in our evaluation. However, without additional modeling information, we are forced to rely on the CALPUFF modeling conducted thus far, which suggests a relatively infrequently, but potentially severe impact on visibility resources at Hercules-Glades. The potential for visibility impacts at more normal SO_2 emissin rate has not been evaluated, so we cannot rule out the potential for an equally severe impact at a lower SO_2 emission rate. We believe that additional analysis would add to our understanding and allow a more accurate assessment of the potential visibility impacts for this project. As such, we would recommend to the State of Missouri that additional visibility modeling be conducted at the 30-day rolling average SO_2 emission rate of 0.12 lb/MMBtu. If modeling at this rate showed little potential for adverse impact, then we would have added confidence that the predicted impacts at the worst-case SO_2 emission rate would be infrequent and we would be inclined to accept the proposed permit for this project.

City Utilities Response:
No response.

Air Pollution Control Program's Response:
To address this and other comments, the Air Program changed the SO_2 emission rate from 0.12 lb/mmBtu, in the draft permit, to 0.095 lb/mmBtu in the final permit. The Air Program performed a visibility impact analysis using an SO_2 emission rate of 0.095 lb/mmBtu. The results of the visibility analysis conducted by the Air Program demonstrate that the maximum change in extinction is 9.95 % at Hercules Glade using the Method 2 analysis along with the 5 parts per billion (ppb) background ammonia concentrations. The maximum change in extinction at Upper Buffalo was 6.69% using the same modeling approach. There were no days over 10% extinction change for either area and there were three (3) days over 5% extinction change for Upper Buffalo, and three (3) days for Hercules Glade. Therefore, no additional visibility modeling is necessary.

For more specific information, please refer to attached memo entitled *Class I Ambient Air Quality Impact Analysis (AAQIA) for City Utilities – Springfield, Southwest Power Station April 2004 Submittal – Visibility* and dated November 19, 2004.

The following comments were submitted to the Air Pollution Control Program by the U.S. Environmental Protection Agency.

Comment:

The SO_2 "baseline" selected by City Utilities to evaluate BACT appears not to be representative of the coals historically used from the Powder River Basin and should be re-evaluated as described in the comments below.

The department proposes a SO_2 BACT limit of 0.12 #/mmBtu, 30-day rolling average. The limit is premised on the use of a worst case "baseline" fuel with a SO_2 inlet potential of 1.462 #/mmBtu in conjunction with a 92 percent removal using a dry spray dry absorber. The BACT limit would apply at all times and would presumably allow for lessor scrubber performance if lower sulfur fuels are burned. While its conceivable that City Utilities might have occasion to use a higher sulfur coal, during periods when the lower sulfur coal is unavailable or otherwise uneconomical, the long term use of such a "baseline" fuel appears to be unlikely based on historical trends observed over the last 24 years for uncontrolled NSPS utility boilers in Region 7.

Based on an evaluation of CEMS data reported for all uncontrolled NSPS Subpart D utility boilers in Region 7, the inlet SO_2 potential for coals combusted from 1980 through 2002 ranged from 0.87 to 0.62 # SO_2/mmBtu, annual average, respectively. See Attachment A for more details. In the years prior to implementation of the acid rain program, uncontrolled NSPS utility units in Region 7 burned coal with a SO_2 potential of 0.87 – 0.73 # SO_2/mmBtu, with the trend generally declining. In the years following implementation of the acid rain program, uncontrolled NSPS utility units in Region 7 burned coal with a SO_2 potential 0.71 – 0.62 # SO_2/mmBtu, again with a lowering trend. In addition, despite these units obligation to comply with the 1.2 # SO_2?mmBtu standard under NSPS Subpart D, there appear to have been incentives other than compliance to use coal with much lower sulfur content. Even if the lower rates at these units are necessary to demonstrate compliance with the acid rain cap and trade program, it shows that the coals necessary to achieve these lower emission objectives are readily available and have been for many years.

In 2002, the highest average SO_2 inlet concentration for a single, uncontrolled NSPS unit in Region 7 was 0.81 # SO_2/mmBtu. This occurred at the Nearman Creek facility in Kansas City, Kansas. Nearman Creek is appropriate for comparison to the City Utilities Southwest Station since both are public power facilities, both have unites of similar size, and both likely face similar constraints when purchasing compliance coal (e.g. low bid contracts, small purchaser). Further, nearly 97% of the emissions data evaluated since 1995 were at or below 0.81 #SO_2/mmBtu and all emissions data analyzed for uncontrolled NSPS Subpart D utility boilers since 1990, including over 144 utility-years of certified emissions data were below a maximum annual potential SO_2 inlet concentration of 0.92 #SO_2/mmBtu. Given the long history and utility-wide nature of this

information, it is apparent that the baseline value used in the City Utilities Southwest SO_2 BACT demonstration is not representative of pre-control emissions likely to occur while combusting PRB coal.

We acknowledge that the annualized SO_2 inlet concentrations described above may not tell the whole story. Sulfur in coal can be reasonably variable and can greatly affect short term averages. As averaging periods shrink, variability becomes an important consideration. As averaging periods expand, the effects of variability are minimized. Since BACT emission limitation must be established using shorter term averages, adjustments to the annual average data may be appropriate, we again looked at the monthly variability for the Nearman plant and other public power facilities in Region 7 from 1997 through 2002. During this period, monthly emissions – showed 97% of the values were less than 0.84 # SO_2/mmBtu and 99% were less than 0.93 # SO_2/mmBtu. Two of the 576 months of data analyzed had SO_2 inlet concentrations greater than 1.0 # SO_2/mmBtu and were clearly outliers. While it is clear that utilities included in the Region 7 analysis have had to periodically use other higher sulfur fuels during time when their preferred fuel supply was unavailable, these infrequent events should not serve as the basis for setting a single BACT standard to represent all periods of operation. In fact, these periods of higher emissions are already reflected in the annual and monthly data analyses described above. Again, this analysis shows that the baseline value used in the City Utilities Southwest SO_2 BACT demonstration may not be representative of pre-control emissions likely to occur while combusting PRB coal.

It is also important to note that when multiple assumptions are used to determine a BACT emission limit they should be evaluated on a consistent time basis. In this case, the BACT limit is derived from applying a 92% removal efficiency to a design sulfur inlet concentration. But, if the 1.462 # SO_2/mmBtu value presented by City Utilities represents a short-term, peak (e.g. instantaneous or 1-hr) inlet concentration value and the 92% SDA removal efficiency represents performance over an extended period such as a year, then this would result in mixed comparison. Such an apples-to-oranges analysis does not provide a meaningful result. The 92% SDA removal efficiency is likely based on annual performance guarantee and may even have a higher performance results on a shorter-term monthly basis. As suggested above, typical 30-day average, <u>maximum</u>, SO_2 inlet concentrations are well below the baseline value used in the proposed BACT analysis. Considered together on a consistent time basis, these multiple assumptions appear to result in a substantially lower SO_2 BACT limit than proposed in the PSD permit.

We also understand an applicants desire for a margin of compliance when setting BACT. But in this case, establishing SO_2 BACT at 0.12 # SO_2/mmBtu effectively allows City Utilities to operate the SDA at an efficiency of 79% when burning PRB coal with an average SO_2 inlet concentration of 0.58 # SO_2/mmBtu and 87% when burning PRB coal with an average SO_2 inlet concentration of 0.93

SO_2/mmBtu. These SO_2 inlet concentrations correspond to the average and worst case monthly average inlet concentrations for all NSPS Subpart D affected public power units in Region 7 between 1997 and 2002. Both percent reduction efficiencies fall well below the long-term design performance anticipated for the SDA as BACT. to compensate for potential under-performance of the SDA when burning lower sulfur PRB coal, we believe the final permit should condition City Utilities to achieve a 92% reduction, based on a 30-day rolling average, in addition to the appropriate BACT emission limitation. To assure that the SDA is operated in a highly effective manner during all periods of operation, the permit should also required City Utilities to install, operate, maintain, and quality assure inlet SO_2 CEMS, in addition to the required stack CEMS, to verify that performance across the SDA is achieved. Since these CEMS are already required by NSPS Subpart Da, it should not be an imposition to include in the permit. We also concur that any additional need for compliance margin has been accounted for in the analysis for lowering SDA performance from 94 to 92%, as described in the supplemental BACT document, and should not be lowered any further.

Lastly, if the department decides not to establish an on-going SDA performance requirement as part of the permit, then we believe that it is essential that the department establish a range of BACT emission limitations for each coal with unique SO_2 inlet concentration characteristics. For example, if City Utilities anticipates they may have to utilize a PRB coal with a 1.462 # SO_2/mmBtu inlet concentration, then a BACT limit of 0.12 may be appropriate during those limited periods of time. On the other hand, if City Utilities combusts PRB with sulfur characteristics more typical of those burned by similar utilities throughout the region, then a SO_2 BACT emission limitation of 0.05 – 0.07 #SO_2/mmBtu appears to be far more appropriate. Any limit that achieves less than 92% control will likely not be deemed to be BACT. This approach is consistent with the principles contemplated under BACT to establish limits based on individual fuels, assures that the SO_2 controls must be operated to their maximum capabilities at all times, and yet allows City Utilities the flexibility to purchase coal anywhere throughout the PRB region in accordance with their purchasing practices and goals.

As a general note, even though we clearly understand that the proposed City Utilities Southwest project will not be an uncontrolled utility boiler subject to NSPS Subpart D. Nevertheless, the data analyzed for these units are highly informative about the SO_2 inlet potential concentration for units combustion PRB coal and should not be overlooked. If the department would like to continue its investigation of the 'baseline' coal issue, we would be glad to share the spreadsheets and analysis that we have already performed as a starting point.

City Utilities' Response:

We disagree with EPA's comment regarding the need for a removal efficiency standard in the Southwest 2 permit. Our concerns are both technical and procedural. Contrary to Region VII's assertions, a

continuous percentage removal standard at or near the top end of the capability of the FGD equipment is a very different matter than the percentage removal requirement of the applicable NSPS.

We agree that Southwest Unit 2 will be subject to Subpart Da removal efficiency requirements and will require a means to determine SO_2 concentration at the FGD inlet. This may be by CEMS or by Method 19 coal sampling. The latter may be advisable in PRB applications, due to analytical problems in measuring true SO_2 concentrations in the high temperature, alkaline dust-laden environment upstream from the dry FGD. In either case, CU will determine SO_2 removal efficiency and report any period less than 70% (on a thirty-day rolling average) as required by Subpart Da. This provision is statutory and does not need to be noted separately in the construction permit.

EPA contends that the permit should dictate, as BACT, that the dry FGD must continuously operate at a higher efficiency rate and has suggested the maximum achievable rate of 92% as the permit target. CU does recognize that the Subpart Da 70% removal requirement would normally not suffice to meet the 0.12 lb/mmBtu limit of the permit. This would only suffice if the inlet SO_2 were lest than 0.40 lb/mmBtu, a level approached only by some premium PRB coals. Southwest 2 will be designed to burn m ore marginal PRB coal, with a maximum SO_2 rate of 1.46 lb/mmBtu and a nominal range of 0.7 to 1.15 lb/mmBtu range. Consequently, the Southwest 2 dry FGD will have to achieve 83% to 90% removal virtually all the time to meet the 0.12 lb/mmBtu limit. Our consultants advise that this would represent yeoman's service for mechanical system inherently limited to 92% efficiency. In addition, EPA's suggestion raises several disadvantages and workability problems; to wit:

A) Running at full equipment capability 100% o f the time increases wear and tear on the FGD, thereby reducing reliability. CU has made a commitment to our community to minimize emissions through good pollution control practices. Excessive FGD downtime due to unnecessary wear and tear does not further this goal, whether excusable under regulatory definition of "malfunction" or not. The system should only have to operate at *maximum* capacity for brief periods when burning worst-case coal or to "catch up" with emission rate requirements following service interruptions.

B) For a given FGD system, removal capacity may not be constant across an entire range of operating conditions, including lower inlet SO_2 loadings. This is a well-documented phenomenon with wet FGD, but has not been studied extensively with dry FGD. 92% removal efficiency at 1.2 lb/mmBtu inlet SO_2 might translate to only 85% removal capability at 0.4 lb/mmBtu inlet. If this proves to be the case

at Southwest 2, a stringent efficiency requirement would militate toward a coal supply with higher inlet SO_2 requirements. This might result in higher than expected SO_2 emissions from Southwest 1 and our James River plant, which normally would be supplied from the same contract(s).

C) For a system rated at 92% removal, any operational glitch would require extensive over-scrubbing in order to make up for last time. No piece of equipment can or should be forced to operate continuously at its maximum rating. This is not advisable from the perspective of long-term care, maintenance, and reliability. In addition, there will be brief periods, as explained in our prior comments, where they dry FGD will have reduced efficiency while atomizers are changed. Following return to normal service, the unit may be able to make up emissions on a pound per million Btu basis or pound per hour basis, but could never make up any lost ground on a percentage removal basis.

D) Pushing the dry FGD to its limit of operation has the potential to damage the downstream baghouse through excessive humidification. Once reagent fee exceeds the limit of saturation, the system is no longer truly “dry” and a wet cake forms on the filer bags. The resulting plugging would damage the bags, forcing premature gab failure and changeout, and could permanently affect baghouse performance.

E) Over-scrubbing requires large excesses of lime reagent, which shows up in the baghouse filter cake as unreacted $Ca(OH)_2$. Upon disposal, this mixture could exhibit environmental properties similar to cement kiln dust.

F) Extreme removal efficiencies on nominal low-sulfur coals can result in outlet SO_2 levels too low to measure reliably (10 ppm or below). We do not propose to have excessive emissions just so we can monitor them better, rather, we point out that administration and enforcement become problematic as measurement uncertainties increase. The subpart Da regulations themselves contain floor level provisions, whereby a unit is deemed to be in compliance with removal efficiency requirements below specified emission levels. This is partly due to the recognized difficulties in measuring such low outlet concentrations and in relying on these uncertain values in subsequent removal efficiency algorithms.

G) There have been at least three PSD permits issued in Region VII in the past five years without this provision. To suddenly decide to change the form of the entire SO_2 standard is arbitrary and capricious. We would be interested in EPA’s rationale for including it at this particular time.

Accordingly, we suggest that the permit should not include a percentage removal requirement. At a minimum, if such a requirement is included, it should be set at a reasonable level between the Subpart Da level and the maximum capability of the system, and should have a "deemed compliant" floor level.

Air Pollution Control Program's Response:

The BACT analysis for SO_2 in the draft permit set an SO_2 emission limit of 0.12 lb/mmBtu on a 30-day rolling average. This analysis was based upon the installation of dry flue gas desulfurization, having a control efficiency of 92 percent. The maximum inlet SO_2 emission rate was considered to be 1.46 pounds of SO_2 per million Btu of coal burnt.

The quality of coal that City Utilities will primarily combust will result in an inlet SO_2 concentration of 0.7 to 1.15 lb/mmBtu. An outlet emission rate of 0.095 lb/mmBtu would correspond to an inlet SO_2 emission rate of 1.15 lb/mmBtu and a 92 percent control efficiency. Since the emission rate of 0.095 lb/mmBtu corresponds to a more representative quality of coal (in regards to sulfur content) that City Utilities plans to combust, the Air Program agrees to change the SO_2 BACT emission limit from 0.12 lb/mmBtu to 0.095 lb/mmBtu.

EPA makes the case in the comment that a more representative inlet SO_2 concentration would be in the range of 0.84 to 0.93 lb/mmBtu. This range is based upon CEMS data reported for all uncontrolled NSPS Subpart D utility boilers in Region VII. The Air Program feels that this data does not represent the entire utility industry as a whole due to the fact that it only looks at uncontrolled boilers. Those boilers which are uncontrolled have to demonstrate compliance with the NSPS Subpart D limits along with the acid rain cap and trade program. In order to demonstrate compliance, many of these companies choose to burn coal with a low sulfur content rather than install add-on controls, thereby narrowing the choices as to what coal can be purchased. Those companies whose boilers have add-on SO_2 controls have a wider selection from which to purchase coal.

It is the Air Program's belief that a baseline inlet SO_2 concentration of 1.15 lb/mmBtu accurately reflects the typical quality of coal, which City Utilities can and will be purchasing. This number is in line with limits placed on other recently permitted pulverized coal fired boiler which will primarily be burning Powder River Basin (PRB) coal. For instance, the MidAmerican Energy Company's permit recently issued by the State of Iowa limits the sulfur content of the coal which can be combusted to 0.625 pounds of sulfur per million Btu. Assuming an average heat value of 8,587 Btu per pound of coal, the inlet SO_2 emission rate would be 1.456 lb/mmBtu.

Based upon this comment, the Air Program agrees to change the SO_2 emission limit of the coal fired boiler to 0.095 lb/mmBtu on a 30-day rolling average.

New Condition:
2.B - Sulfur Oxides (SO_2) to 0.095 lbs/mmBtu on a 30 day rolling average.

Comment:
EPA recently promulgated final performance specifications, PS-11, for installation, operation, maintenance, and quality assurance of continuous particulate matter emissions monitoring systems. For a number of reasons, we believe that the proposed City Utilities Southwest Unit 2 installation is a prime location to require the use of this monitoring technology. First, this is a state-of-the-art utility boiler which will benefit from a host of new technology. Since the PSD program is meant to be technology forcing, requiring a PM-CEMS would be consistent with that goal. Second, utilities can emit large amounts of particulate matter when control devices are not functioning correctly. The PM-CEMS is a valuable tool to help enhance baghouse performance while also providing information to verify that the unit is meeting its PM BACT emission limitation. Third, utility companies typically have very experienced instrumentation staff. City Utilities has a lot of experience using monitors under the acid rain program and can extend that knowledge into moving the PM-CEMS technology forward. City Utilities also has the expertise to manage the acquisition, installation, operation of complicated monitoring technology and oversee the critical testing that is essential to the proper functioning of the PM-CEMS. Lastly, utility companies typically have the economic resources to purchase complicated monitoring technologies and the support necessary to ultimately make them work. When all of these critical factors come together, it is an appropriate time to promote the technology. In that regard, we strongly encourage the department to require PM-CEMS for the new Southwest unit.

City Utilities' Response:
We fail to see how this facility would represent a good test application for particulate matter CEMS. Unlike SIP and Subpart D sources, this unit will be subject to an NSPS emission limit for total particulates and to a permit limit for PM_{10}. If we were to install a PM-CEMS, it would only measure the former, and we would still have to have some performance-based method to reasonably certify compliance with the PM_{10} limit. This would entail two separate CAM systems, one of which (the PM-CEMS) would be totally superfluous.

Air Pollution Control Program's Response:
The permit contains scheduled testing for PM_{10} along with operational requirements for the baghouse. Therefore, the Air Program believes that there is adequate requirements contained in the permit in order verify that the baghouse is operating correctly and the PM_{10} emission limit is being met.

Comment:
Condition 2 establishes emission limitation for HF, HCl, and mercury which are verified through an initial, one time stack test required by Condition 6. The limitation for HF and HCl were imposed primarily for the purpose of keeping the proposed project out of 112(g) technology review for hazardous air pollutants. The limit for mercury limit was imposed to keep the project out of BACT review under PSD. Even with the limits on potential to emit, all are at or very close to their respective technology review thresholds. In the case of HCl, the potential to emit presumes a scrubber performance of 96%. If performance drops to 95%, then HCl emission would be over the 112(g) review threshold and could trigger additional review for all HAPs, including the possibility of add-on controls such as activated carbon injection for mercury. It is imperative, then, that these limits continue to be complied with throughout the lifetime of the project.

While initial stack testing may be appropriate to verify that City Utilities is meeting its HAP limits following initial startup of the boiler, there are no provisions in the permit for verifying on-going compliance with the HCl, HF, and mercury emission limitations. Periodic stack testing may further inform the compliance verification, but it does not assure that the control equipment, in this case the SDA for HCl and HF, continues to perform at the level needed to keep these pollutants out of 112(g) review. Consequently, we recommend that the permit include a condition that requires collection of baseline and ongoing SDA parametric data sufficient to verify that the scrubber continues to operate at the 96% performance level necessary to validate the 112(g) non-applicability assumptions for HCl. If the department is unable to specify which parameters it wants City Utilities to measure, then we recommend inclusion of a condition which requires City Utilities to submit a "parametric measurement and analysis plan" for approval prior to the first HCl baseline performance test. In addition, we think it is appropriate to place the consequences statement, "In the event that the stack test results [or ongoing parametric data] demonstrate that the potential of any single HAP exceeds 10.0 tons per year or the potential emissions of all HAPs combined exceed 25.0 tons per year, City Utilities will have to submit a case-by-case MACT analysis for the new pulverized coal fired boiler" as a condition in the permit along with the statement already made in the " Review Summary".

City Utlities' Response:
We concur that, for CAM purposes, periodic stack testing for HCl and HF, together with ongoing parametric measurements, would be advisable as a means to elicit reasonable compliance assurance. CU would agree to submit a parametric monitoring plan, if requested, following the initial performance tests for these substances. We would suggest follow-testing at five-year interval to be consistent with Title V renewal cycles.

Air Pollution Control Program's Response:
The Air Program agrees with the comments and will change as requested.

New Condition:

6.E. Within 90 days of completion of the initial compliance testing for HCl and HF required by Condition 6.A, City Utilities shall submit a parametric monitoring plan based upon the stack test results for HCl and HF to the Air Pollution Control Program for approval.

Comment:
Conditions 2.C and 2.E establish short term NAAQS-based, mass emission limitations for SO_2 and CO. Since City Utilities is already required to install SO_2 mass measurement system pursuant to the acid rain program, we encourage the department to further condition the permit to require the use of the acid rain CEMS to verify compliance with the short term SO_2 limit. In addition, we encourage the department to also require the use of the flow monitoring system required by the acid rain program in conjunction with the CO concentration CEMS required in Condition 7 to verify compliance with the short term CO mass emission limitation.

City Utilities' Response:
For the mass-based CO and short-term SO_2 emission limits, we agree it would be reasonable to specify Part 75 flow monitoring system for calculating mass emissions. The CEMS data software should easily accommodate this.

Air Pollution Control Program's Response:
The Air Program agrees with this comment and believes that the permit already required the use of CEMS data to demonstrate compliance with short term SO_2 and CO emission limitations. Condition 8.C states:

City Utilities shall maintain records demonstrating compliance with the NO_X, SO_2, CO, and opacity limits found in Special Conditions 2.A through 2.E using CEMS data outlined in Special Condition 7.

Comment:
Condition 10.A requires City Utilities to conduct post construction monitoring for SO_2 for one year after the unit is fully operational. Following completion of the post-construction monitoring, the department can suspend the monitoring at its option. Since this condition does not make clear that this is "ambient" monitoring, it would be helpful to do so. In the event this condition was intended to also mean "stack" monitoring, we believe that such monitoring should, and under the NSPS and acid rain programs must, continue throughout the life of the unit.

City Utlities' Response:
We interpret Condition 10.A to refer to post-construction ambient monitoring. There would be no objection to making the clarification suggested by EPA.

Air Pollution Control Program's Response:
The Air Program agrees with the comments and will change as requested.

New Condition:
10.A - City Utilities shall conduct post construction ambient monitoring for SO_2 for a period no less than one (1) year after the PC boiler Number 2 (Emission Point E100) is fully operational. Monitoring may be discontinued upon written request and approval from the Air Pollution Control Program's Director.

The following comments were submitted to the Air Pollution Control Program by City Utilities.

Comment:
City Utilities acknowledges the rationale for the gas burning restriction in Condition 1.A. This is predicated on the general lack of emissions performance data for units operating in this configuration on natural gas. To support any future request for approval under this condition, we suggest that the phrase "other than startup or flame stabilization" be replaced with "other than startup, flame stabilization, or emissions testing."

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will make the following changes:

New Condition:
1.A - In the event that natural gas will be combusted in the pulverized coal (PC) fired boiler Number 2 (Emission Point E100) for purpose other than startup, flame stabilization, or emissions testing, City Utilities shall:

Comment:
Condition 1.D appears to require retirement of one coal belt or the other. We believe the intent here is to ensure operation of only one belt *at any given time*, to be consistent with the modeled scenario. In addition, this condition should reference both emission points by number, E06 and E101.

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will make the following changes:

New Condition:
1.D - City Utilities shall operate only one (1) of the underground conveying systems (Emission Point E06 and E101) at any given time in which coal is conveyed from the storage pile to the boiler.

Comment:
Condition 1.E is inconsistent with the modeling scenario, which included coal unloading from E01 and E120 at a rate of 18,000 tons per day *each*. Since both of these points use the same emission factors and controls, we would suggest a limitation of 36,000 tons per day combined throughput for these points.

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will make the following changes:

New Condition:
1.E - City Utilities shall not unload from railcars (Emission Points E01 and E120) more than 36,000 tons of coal in any 24-hour period.

Comment:
Condition 2.C describes the modeled operating scenario in which the unit must run uncontrolled or partially controlled for SO_2 during short-term routine maintenance on the dry FGD system. We acknowledge the need for this provision, but disagree with the wording because it is much more restrictive than the modeled scenario. Importantly, this may result in undue wear and tear on the FGD system and be counterproductive.

In discussing this provision, it is important to note that it refers to events that would occur infrequently and for very short periods of time. It is intended to address, as an example, the routine replacement of an FGD spray atomizer, which is required periodically in order to maintain high SO_2 removal efficiencies on a continuing basis. During the period immediately following such a replacement, the FGD may require a period of adjustment, which might include some over-control in order to make up for the brief period of no control.

The situation is illustrated on the attached figures. Figure A shows the modeled scenario, in which the unit operates at its maximum uncontrolled output for three hours of the day. This would represent the worst-case emissions profile during an atomizer changeout. In order to meet the 24-hour average, the unit must then operate at its maximum achievable removal efficiency for the next 21 hours. This maximized mode of operation is very taxing on the equipment, and vendors have advised that it should be undertaken only briefly and when absolutely necessary in order to avoid long-term damage to the FGD system.

Figure A represents the most extreme situation and was selected as the worst case modeling input. Still, it was shown to be protective of Class I and Class II air quality. Figures B and C show alternative, more reasonable scenarios, in

which Southwest 2 exceeds the 24-hour line briefly but is able to meet the 24-hour emission limit with less stressful rates of control for the balance of the period. The modeling would indicate that both of these scenarios are protective of air quality, since they have a lower 3-hour peak than, and the same 24-hour emission rate as Figure A. However, the permit as drafted, would require both of these scenarios to overcontrol to the maximized control level, as shown in Figure D. This may be more protective of air quality, but is more restrictive than the modeled scenario, involves operating at an ill-advised control rate each time an atomizer is replaced, and essentially penalizes the operators for performing a changeout more quickly or more cleanly than the modeled maximum.

In our discussions with Air Program Staff, we understand that the rationale behind the restriction in Condition 2.C(2) is to avoid scenarios as shown in Figures E and F. These situations involve modest 3-hour peaks over more than one 3-hour period in a day, but still meet the 24-hour limit with moderate overcontrols. These scenarios should be equally protective of 24-hour air quality, but the impact on 3-hour increment is undeterminable, since downwind effects may be additive (due to dramatic wind changes) and were not modeled as such. We suggest that these scenarios could be precluded by allowing the 24-hour mass emission rate to be exceeded *only once* in any 24-hour period, and then to a level no greater than the modeled maximum.

Accordingly, we suggest replacing existing Conditions 2.C(1) and (2) with the following:

C. SO_2 emissions may not exceed an average of 490.5 lb/hr in any rolling 24-hour period, subject to the following:
   1) Each rolling 24-hour period may have a maximum of one discrete 3-hour period in which average SO_2 emissions exceed 490.5 lb/hr.
   2) For that 3-hour block of time, the SO_2 emissions may not exceed 6,785 lbs.

Air Pollution Control Program's Response:

The Air Program agrees with this comment and will make the following changes:

New Conditions:

2.C . SO_2 emissions may not exceed an average of 490.5 lb/hr in any rolling 24-hour period, subject to the following:
   1) Each rolling 24-hour period may have a maximum of one discrete 3-hour period in which average SO_2 emissions exceed 490.5 lbs/hr.
   2) For that 3-hour block of time, the SO_2 emissions may not exceed 6,785 lbs.

Comment:
The value shown for sulfuric acid mist should be $1.84x10^{-4}$ lbs/million Btu, rather than the value shown. The original value of $9.82x10^{-6}$ was included in the application, but was later found not to be applicable to units equipped with SCR for NOx control (there is a slight increase in SO_2 to SO_3 conversion across the catalyst). The higher value of $1.84x10^{-4}$ lbs/million Btu was included in air modeling analyses.

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will make the following changes:

New Condition:
2.H Sulfuric Acid Mist (H_2SO_4) to 1.84 X 10^{-4} lbs/mmBtu.

Comment:
The H_2SO_4 limits in Condition 2.I mirror the SO_2 limits in 2.C, and have the same inconsistency discussed above. We suggest replacing existing 2.I with:

I. H_2SO_4 emissions may not exceed an average of 0.74 lb/hr in any rolling 24-hour period, subject to the following:
   1) Each rolling 24-hour period may have a maximum of one discrete 3-hour period in which average SO_2 emissions exceed 0.74 lb/hr.
   2) For that 3-hour block of time, the SO_2 emissions may not exceed 10.22 lbs.

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will make the following changes:

New Condition:
2.I. H_2SO_4 emissions may not exceed an average of 0.74 lbs/hr in any rolling 24-hour period, subject to the following:
   1) Each rolling 24-hour period may have a maximum of one discrete 3-hour period in which average SO_2 emissions exceed 0.74 lb/hr.
   2) For that 3-hour block of time, the SO_2 emissions may not exceed 10.22 lbs.

Comment:
The HCL and HF acid gas emission limits shown in Conditions 2M and 2N, respectively, are too high. The values shown in the draft are AP-42 pre-control figures, which should be adjusted for removal through the dry FGD. The correct values shown in the application and used in the permit analysis were 0.00073 lbs/million Btu for HCl and 0.00037 lbs/million Btu for HF.

Air Pollution Control Program's Response:
The uncontrolled emission rates for HCl and HF were inadvertently used in the draft permit. The Air Program agrees to correct the emission factors for HCl and HF in order to reflect controlled emissions. In addition, the condition numbering was incorrect in the draft permit. The Air Program agrees with this comment and will make the following changes:

New Condition:
2.L. Hydrogen Chloride (HCl) to 0.00073 lbs/mmBtu.

2.M. Hydrogen Fluoride (HF) to 0.00037 lbs/mmBtu.

Comment:
Emission Point E102 may involve a totally enclosed process. In the source table in Condition 3.B, we suggest that Note 1, currently affixed to E103, should also apply to E102.

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will reference the existing Note1 referenced for emission point E103 for emission point E102 found in the table entitled *PM_{10} Emission Sources* located in Condition 3.B.

Comment:
The missing data routine in Condition 7.C(3) is appropriate for SO_2, but not for NOx. We recommend a new 7.C(4) to comport with the NOx missing data requirements of 40 CFR §75. This load-bin procedure would also be appropriate for missing CO data as well, since CO emissions may be load-related.

4) For each hour of missing NO_X (or CO) emissions data, City Utilities shall substitute data by:

   a) Whenever the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of

the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(1) For a missing data period less than or equal to 24 hours, substitute, as applicable, for each missing hour, the arithmetic average of the flow rates or NO_X emission rates or NO_X (or CO) concentrations recorded by a monitoring system during the previous 2,160 quality- assured monitor operating hours at the corresponding unit load range or operational bin as determined using the procedure in Appendix C to 40 CFR Part 75.

(2) For a missing data period greater than 24 hours, substitute as applicable, for each missing hour, the greater of:

(a) The 90th percentile hourly flow rate or the 90th percentile NOx (or CO) emission rate or the 90th percentile NOx (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75; or

(b) The 90th percentile hourly flow rate or the 90th percentile NOx (or CO) emission rate or the 90th percentile NOx (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75; or

(c) The average of the recorded hourly flow rates, NOx (or CO) emission rates or NOx (or CO) concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

b) Whenever the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(1) For a missing data period of less than or equal to 8 hours, substitute, as applicable, the arithmetic average hourly flow rate or NOx (or CO) emission rate or NOx (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75.

(2) For a missing date period greater than 8 hours, substitute, as applicable, for each missing hour, the greater of:

(a) The 95th percentile hourly flow rate or the 95th percentile NOx (or CO) emission rate or the 95th percentile NOx (or CO) concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in Appendix C to 40 CFR Part 75; or

(b) The average of the hourly flow rates, NOx (or CO) emission rates or NOx (or CO) concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

c) If the monitor availability is less than 90%, the owner or operator shall obtain actual emission data by an alternative testing or monitoring method approved by the Department.

Air Pollution Control Program's Response:
The Air Program agrees to add the requested wording as Condition 7.C.4 to the permit.

Comment:
In order to apply Condition 7.C(3) and the suggested 7.C(4), we recommend inclusion of a method to determine monitor availability:

" The owner or operator shall use the procedures described in 40 CFR §75.32 to determine monitor availability."

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will make the following changes:

New Condition:

7.C Compliance with all non-NSPS CO, NO_X, and SO_2 emissions limits of this permit shall be demonstrated through the use of the required CEMS. City Utlities shall use the procedures describe in 40 CFR §75.32 to determine monitor availability.

Comment:
The Installation Description on draft page 15 indicates that the turbines at Southwest Power Station were not installed in 1982. Actually, the record should show that they *were* installed that year, and the sentence should read "not installed until 1982."

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will correct the permit wording to read that that the turbines were installed in 1982.

Comment:
The sixth full paragraph on draft page 16 indicates that the coal for Southwest 2 will have an ash content of 6.9%. In actuality, this is the design maximum for the unit, so should read "up to approximately 6.9%."

Air Pollution Control Program's Response:
The Air Program agrees with this comment and will correct the permit wording to read that coal combusted in the Southwest 2 boiler has an ash content up to 6.9%.

Comment:
The third full paragraph on page 17 states that City Utilities does not plan to install mercury control systems at this time. City Utilities included the mercury control systems in the modeling revisions and we do intend to install mercury control available at the time of construction. At this point we do not know if control will be by activated carbon injection, other sorbent injection, or passive collection devices, but it will be the most effective system that has been shown to be compatible with the SOx, NOx, and PM pollution control technologies.

Air Pollution Control Program's Response:
The Air Program misunderstood City Utilities intentions of installing mercury controls. The Air Program agrees to change the wording of the permit.

New Wording:
City Utilities is anticipating controlling mercury emissions by means of injecting powdered activated carbon. However, a final decision as to the exact method of mercury control has not been made. City Utilities does plan on installing some type of mercury control, but is holding off making a final decision until a later date so that the most effective system of mercury control that has been shown to be compatible with the NO_X, PM, and SO_X pollution control technologies can be determined. If the mercury control is not powdered activated carbon, then it will be at least as effective.

Comment:
The fourth full paragraph on draft page 17 indicates that coal will be delivered to Southwest Power Station by rail and transported to James River by truck. However, this permit only allows for that potential delivery plan, as indicated in the sentence prior. At this point, no decision has been made to alter our delivery to either plant. Accordingly, this sentence should state that coal *would* be delivered to Southwest and transported to James River *if* this option is exercised in the future.

Air Pollution Control Program's Response:
The Air Program agrees to correct the permit wording to read as requested.

New Wording:
In addition to the new pulverize coal boiler and its associated equipment, City Utilities will also be adding a new coal unloading station that will allow the use of the existing rail access at the Southwest Power Station as an additional coal delivery point for their James River Station (077-0005). Coal would be delivered to the Southwest Power Station by rail and the transported by truck to James River if this option is exercised in the future.

Comment:
In the second full paragraph on draft page 18, the value shown for sulfuric acid mist should be 1.84×10^{-4} lbs/million Btu, rather than the value shown.

Air Pollution Control Program's Response:
The Air Program used an inappropriate emission rate in the draft permit that was not consistent with what was submitted in the application. The application indicated that the emission rate was 1.84×10^{-4} lb/mmBtu. The Air Program agrees to change the emission rate to reflect what was submitted in the application and used in modeling.

Comment:
In the third full paragraph on draft page 18, the drift rate lost from the cooling tower should be 1.50 gallons per minute rather than 0.50 gpm.

Air Pollution Control Program's Response:
A typographical error occurred in drafting the permit and the Air Program agrees that the drift rate lost from the cooling tower should be 0.50 gallons permit minute. The Air Program agrees to correct the mistake.

Comment:
In the fifth full paragraph on draft page 18, the words "rail care" in the first sentence should read "rail car." In addition, the model included coal unloading at a rate of 36,000 tons per day rather than 18,000. Please see comment I.C, above.

Air Pollution Control Program's Response:
The Air Program agrees with the comment and will make the following the appropriate changes to the permit.

Comment:
In Table 1 on draft page 19, the emissions for H_2SO_4 should be 2.2 tons per year.

Air Pollution Control Program's Response:
The H_2SO_4 emissions found in Table 1 were based upon incorrect H_2SO_4 emission rates. As explained in previous response, the appropriate H_2SO_4 emission rate should be 1.84 $x10^{-4}$ lb/mmBtu. The annual H_2SO_4 emissions based upon the corrected emission rate are 2.2 tons per year. As such, the Air Program agrees to make the requested changes.

Comment:
A. Under Special Condition 1B(1), the words "boiler" and "for" require separation. Under Special Condition 1B(2) the word "great" should be "greater"
B. Under Special Condition 1.F the word "May" should be "map."
C. Under Special Condition 1.H the table identifies E11 as a truck unloading operation. This should say "truck loading."
D. Under Special Condition 3.B, the description assigned to Emission Point E117 should read "Lime transfer to *feed* bins."
E. Under Special Condition 7.C(2), the word "sued" should be "used."
F. Under Special Condition 7.C(3)(a), the word "be" should be "by". Under Special Condition 7.C(3)(a)(2), the word "great" should be "greater."

G. Under Special Condition 7.C(3)(c), there appears to be a tabulation error, which makes this major point to appear to be a subpoint under 7.C(3)(b)(2).
H. Under Special Condition 8.H, the rail car unloading point identified as E06 should be two points, E01 and E120.

Air Pollution Control Program's Response:

The requested changes are due to typographical mistakes in the draft permit. As such, the Air Program agrees to make the appropriate corrections as requested.

The following comments were submitted to the Air Pollution Control Program by the Ozark Chapter/Sierra Club. The comments will be paraphrased below due to the length of the comments. The original comments along with City Utilities response may be read in full in the Attachments.

Comment:

The draft permit unlawfully and arbitrarily fails to require City Utilities to reduce emissions of regulated pollutants to the level that qualifies as BACT.

Air Pollution Control Program's Response:

The Air Program followed the BACT guidelines as provided by EPA. As stated in the New Source Review Workshop Manual, "During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring."

The Air Program considered many recent proposed and/or permitted coal fired boilers in order to determine the proper control technologies and associated emission rates for each pollutant. In addition to examining previously permitted control technologies and emission rates, the Air Program reviewed the required controls and emission rates to determine if they were based upon BACT or LAER reviews and if the requirements were based upon location of the installation (i.e. ozone nonattainment areas). Other items that went into the overall decision making process when comparing the City Utilities project with others were averaging time of limits, actual work experience of plants using similar controls, and the types of coal.

The Air Program deemed that the installation of selective catalytic reduction (SCR) should be required for the control of NO_X emissions from the boiler based upon this comprehensive review. This determination is consistent with other proposed or permitted boilers. Once the control device was established, it was necessary to establish a BACT emission limit for NO_X.

Kansas City Power and Light (KCPL) was issued a permit for a pulverized coal fired boiler at their Hawthorne location in 1999. The permit established a BACT limit for NO_X of 0.08 lb/mmBtu on a 30 day rolling average. However, for the first three years of operation, the limit was set at 0.12 lb/mmBtu on a 30 day rolling average. This "grace" period was given so as to allow KCPL time to gain experience and fine tune the equipment. KCPL was able to demonstrate compliance with the 0.08 lb/mmBtu during the first half of the three (3) year life span of the catalyst.

As time went on the catalyst showed significant degradation and was unable to demonstrate compliance with the 0.08 lb/mmBtu NO_X limit. Based on the experience gained at KCPL's Hawthorne site, it was determined that the catalyst degraded at a faster rate when combusting subbituminous PRB coals versus higher sulfur bituminous coal. The State of Nebraska recently issued a permit for the Whelan Energy Center having the exact same NO_X limitations as was given in the KCPL.

The State of Iowa recently issued a permit to MidAmerican Energy Company for the installation of a coal fired boiler. In that permit, the State of Iowa set the BACT emission limit for NO_X at 0.07 lb/mmBtu using SCR as a control. This plant has yet to be fully constructed, and thus has not been able to show compliance with that limit, especially over a three (3) year life span of the catalyst.

The Air Program reviewed the MidAmerican Energy Company's permit and believes that in order to continually meet the 0.07 lb/mmBtu NO_X limit when burning PRB coal, the SCR catalyst would have to be replaced more frequently than every three (3) years. The Air Program asked City Utilities to examine the cost of replacing the SCR catalyst every year and a half. The review found that the cost of replacing the catalyst every year and a half was significantly higher than when considering the catalyst life span of three (3) years. The major cost differences are due to catalyst replacement cost, the replacement interval, and replacement power costs.

The Air Program also considered eastern coal fired plants which have been reported to have achieved NO_X emission numbers around 0.07 lb/mmBtu and lower. When examining these units, it was determined that many of these units were being controlled in order to meet NO_X SIP-Call mandates. Emission limits from many of these units were based upon tonage limits rather than short term limits. In addition, many of these units were only operated during peak ozone seasons and not year round. Thus, they have not experiences the catalyst degradation associated with PRB coal due to the year round operation as seen at the KCPL Hawthorne boiler.

Based upon this information, the Air Program determined the appropriate BACT limit for NO_X for this project was 0.08 lb/mmBtu. The permit does not allow for a "grace" period of three (3) years where the limit is 0.12 lb/mmBtu as seen in the Whelan Energy Center permit and the KCPL permit. This limit was found to be consistent with other recently proposed and final permits for coal fired boilers.

In regards to SO_2 emissions, the Air Program looked at several different types of control options. It was determined that wet flue gas desulfurization (wet FGD) or dry flue gas desulfurization (dry FGD)

provided the best, proven technology for SO_2 control. Both of these technologies have been presented as BACT in recent proposed and final permits. The Air Program acknowledges that the wet FGD systems provide slightly better controls for SO_2 than dry FGD systems do. The use of wet FGD systems versus a dry FGD system will result in a significant energy penalty to facility operation in the form of electricity demand required for operations of ancillary equipment as. The wet FGD will have an additional back pressure on the exhaust system that results in a slight reduction in output. As a result of in the increased energy demands, the boiler would have to be sized bigger and combust more fuel in order to produce the same net electrical output. Greater emissions of other pollutants would result due to the increase in fuel combustion. It was also determined that the wet FGD system is less effective at controlling sulfuric acid mist, HAPs, total particulates, PM_{10}, as well as fine particulates.

From a technical standpoint, the wet FGD system is less desirable than the dry FGD. The flue gas exiting the absorber from a wet FGD system is saturated with water and does still contain some SO_2. These gases are highly corrosive to any downstream equipment. It is possible to minimize the corrosion of the equipment by reheating the flue gases above the dewpoint temperatures and/or selecting construction materials and design conditions which will resist the corrosive conditions. However, these options do add cost to the system. Another aspect of the wet FGD system which is less desirable on a technical viewpoint is the wastewater produced, which is not a byproduct of the dry FGD system.

When taking all of these aspects into consideration, the Air Program determined that the dry FGD system was a better option for the City Utilities project. As stated earlier, dry FGD systems have been selected as BACT for other recently proposed or permitted boilers burning PRB coal.

The Air Program did examine the possibilities of requiring City Utilities to wash the coal in order to remove sulfur. For more information on why coal washing was not required, please refer to the specific comment below dealing with coal washing.

The draft permit set the BACT emission limit for SO_2 at 0.12 lb/mmBtu. This number is consistent with other recently proposed or permitted boilers burning PRB coal. However, when re-examining the baseline, uncontrolled emission rate for SO_2, the Air Program determined that the number used initially was too high. The new limit was set at 0.095 lb/mmBtu. For further discussion regarding this issued, please refer to EPA's comment concerning the SO_2 BACT emission limit.

City Utilities permit does contain emission limitation for sulfuric acid mist. However, this number does not constitute a BACT emission limitation. A separate BACT analysis was not required for sulfuric acid mist due to the fact that the potential sulfuric acid mist emissions are below the significant level of 7.0 tons per year.

City Utilities proposed in their application the use of a baghouse as control for PM_{10}. Since this option represented the highest level of control, the Air Program did not investigate other control technologies. This determination was found to be consistent with other recently proposed or permitted coal fired boilers. The BACT emission limit for PM_{10} was set at 0.018 lb/mmBtu. This limit included both filterable and condensable particulates. This limit is consistent with other recently proposed or permitted coal fired boilers.

Comment:

Coal washing was unlawfully omitted from consideration in the BACT analysis.

Air Pollution Control Program's Response:

The Air Program did examine the possibilities of requiring City Utilities to wash the coal in order to remove sulfur. Based on the research, coal washing is a potential method for reducing SO_2 emission from the boiler as it would reduce the amount of sulfur contained in the coal. The Illinois Environmental Protection Agency examined coal washing their review of the Prairie State Generating Station. They concluded that a 20 percent reduction in the sulfur content associated with coal washing would result in 22 to 25 percent of the coal being lost. For the Prairie State Generating Station, which is a 750 net MW boiler burning high sulfur coal, the cost of coal washing would result in a cost of $10,000 per ton of SO_2 removed.

City Utilities is going to burn low sulfur coal and thereby would expect to see a small reduction in sulfur content for the same amount of coal lost. Taking this into account along with the wastewater issues that coal washing creates, the Air Program determined that coal washing did not merit further consideration under the BACT analysis. In addition, the Air Program looked at several recently permitted coal fired boilers, located in Iowa, Nebraska, Illinois, and Kentucky) and none of those permits required coal washing.

Comment:
The Department of Natural Resources unlawfully failed to consider alternative boiler designs and fuel types that could achieve greater reduction in emission reductions.

Air Pollution Control Program's Response:
As was stated in the draft permit, City Utilities did do a study in which they examined several different types of technology. In the study they compared emissions, costs, efficiency, start-up time, fuel, availability, and reliability of different types of technology. They concluded that the subcritical pulverized coal fired boiler unit was the best option for their needs.

In regards to integrated gasification combined-cycle (IGCC), City Utilities determined that the availability and reliability of the IGCC plants (based on the small number in existence) did not meet the requirements necessary for a base load unit. Other barriers to the IGCC are its high capital costs and operating and maintenance costs. Based upon the few existing IGCC projects, the NO_X emission rates achieved by IGCC units are similar to those achieved by pulverized coal fired units with add-on controls.

City Utilities' conclusions are further supported by Illinois Environmental Protection Agency. In their draft permit for Prairie State Generating Station they state:

> "The higher costs and the uncertainties associated with IGCC would prevent the proposed plant from being developed. At the present time these factors would also likely precluded use of IGCC for other similar power plant projects being developed primarily with private (non governmental) financing.

Comment:
The Department of Natural Resources unlawfully failed to consider the possibility for technology transfer in establishing BACT for this facility.

Air Pollution Control Program's Response:
The Air Program believes a thorough investigation of all appropriate control technologies was conducted. For more specific details on the BACT analysis performed please refer to the permit and the previous two comments.

Comment:

The draft permit unlawfully exempts periods of start-up, shutdown, and malfunction from compliance with BACT limits.

Air Pollution Control Program's Response:

Periods of start-up, shutdown, and malfunctions are covered under 10 CSR 10-6.050 *Start-up, Shutdown, and Malfunction Conditions.*

Comment:

The emission limits in the draft permit are unenforceable.

Air Pollution Control Program's Response:

The permit does not explicitly specify a test method for determining compliance with the limits of the regulated pollutants. However, Condition 6.C of the permit required City Utilities to submit a Proposed Test Plan to the Air Pollution Control Program at least 30 days prior to testing. At this time, City Utilities will have to list the test methods they plan on conducting in order to show compliance with the appropriate conditions. The Air Program will review the Proposed Test Plan at that time and decide whether to approve. Condition 6.C goes on to state that the test plan must be approved by the Air Pollution Control Program prior to conducting any testing.

The permit does required initial performance testing for VOC, PM_{10}, mercury, lead, HCl, and HF. The Air Program changed the permit to require this testing every five (5) years after the initial testing. In addition to requiring testing every five years, the permit requires City Utilities to submit a parametric monitoring plan for HCl and HF. The parametric monitoring plan will be used by City Utilities to demonstrate compliance with the HCl and HF limits.

The permit did not include CO in the list of pollutants requiring initial performance testing as listed in Condition 6.A. However, the permit requires City Utilities to install and operate CEMS for CO. The CEMS data will be used to show compliance with the CO limit found in the permit.

The permit requires City Utilities to develop a correlation between SO_2 and H_2SO_4 emissions. The permit goes on to require City Utilities to use this correlation, along with actual SO_2 emissions data, to show compliance with the H_2SO_4 limits.

The intent of Condition 10.A was in regards to post construction ambient monitoring for SO_2 and not emissions monitoring of SO_2 from the boiler. The permit has been modified to clarify any confusion.

The opacity limits of the boiler that City Utilities must comply with are those found in the NSPS Subpart Da. City Utilities must comply with this limit whether or not it is explicitly state in the permit.

Comment:

The Department of Natural Resources should require City Utilities to comply with MACT requirements.

Air Pollution Control Program's Response:

EPA has yet to promulgate a MACT standard applicable to the equipment or the installation at the point in time. In the absence of an applicable promulgated MACT, a case-by-case MACT determination is required under Section (9) of Missouri State Rule 10 CSR 10-6.060 if the potential HAP emissions are greater (and are not specifically limited by permit conditions) than 10.0 tons per year for any single HAP or 25.0 tons per year for all HAPs combined.

Potential emissions of all expected HAPs were calculated as a part of the application review and found to be less than 10.0 tons per year for any single HAP and less than 25.0 tons per year for all HAPs combined. Thus, the Air Program has no regulatory authority to require City Utilities to conduct a Section (9) review for the equipment being installed. The permit does require testing and monitoring of some of the HAPs, which had the highest potential emissions. In addition, the permit requires City Utilities to resubmit HAP emission calculations if the testing shows that emission factors used in the application were too low. At that time, if the revised calculations show the potential emissions of HAPs are greater than 10.0/25.0 tons per year, then City Utilities will have to submit a Section (9) review and install any controls deemed necessary. If and when EPA promulgates a MACT standard applicable to the equipment or installation, City Utilities will have to comply with any and all limits presented in the MACT.

Comment:
City Utilities and the Department of Natural Resources should be concerned about the potential environmental and economic effect of the emissions of carbon dioxide from the proposed Southwest Unit 2.

Air Pollution Control Program's Response:
Carbon dioxide is not a regulated pollutant under the Clean Air Act or the Missouri State Regulations. Thereby, the Air Program does not have the regulatory authority to require City Utilities to review and ultimately install control for carbon dioxide.

The following are written comments submitted to the Air Pollution Control Program by private citizens.

Comment:

I am writing with concerns about the permit for a new electrical power plant in southwest Springfield, MO. I hope that the Department of Natural Resources investigates all aspects of air quality and denies the permit for a second plant at the current plant's location. If those who make the final decision on such a permit agrees to approve a permit (which the newspaper seems to indicate as a "done-deal"), my desire is that the department requires heavy containment of air pollutants. The following paragraph will explain my concerns.

I am a resident who lives in the southwest part of the city and who has experienced episodes of heavy soot. These episodes have increased during the last few years and is somewhat of a surprise because my subdivision is over 5 miles cross-country from the current power plant. When I moved to southwest Springfield in 1993, there was no noticeable air particles. I could hang clothes out to dry without concern. During the past few years I have not been able to dry clothes on the line when the wind is from the northwest or west. Clothes, if hung out during these directional winds, will be dingy gray and smell awful within two hours. I now have to wash the clothes line before I use it. The residue on the wet towel is always black. A recent occurrence (early May) for one of my neighbors indicates the severity of the problem. They left their newish car outside of their garage for approximately seven hours. When he went to drive the car into the garage, the car was covered in a heavy, visible layer of gray particles which appeared to be soot. If layers of soot is appearing on objects left outside for a period of time, these same particles are being inhaled by people who live in the downwind paths from the current plant.

I have sought help and/or information from local officials but they, while nice, really don't seem to be able to remedy the problem or deny that a problem exists. I have learned that the current southwest electrical plant started operating 24 hours a day, seven days a week about 5 years ago, which would coincide with the beginning of my neighborhood's soot problem.

Placing a second coal-burning electrical power plant next to the current plant will exacerbate our already existing problem. I hope that the Department of Natural Resources considers all aspects of the quality of life in Springfield before granting a permit.

City Utlities' Response:

No response.

Air Pollution Control Program's Response:

The Air Program conducted an extensive review of City Utilities application to construct a pulverize coal fired boiler at their existing Southwest Power Station. The installation of a baghouse was determined to be the best control for particulate emissions from the boiler. The permit sets specific emission rates, which City Utilities must meet, for particulate emissions from the baghouse. In addition to particulate emissions from the boiler, the permit also requires specific types of control from haul roads, coal handling equipment, and coal piles. For a more detailed description of these controls along with controls of other pollutants from the boiler, please refer to the permit.

In addition to reviewing the control technology to be used on the different equipment and operations, the Air Program conducted an extensive modeling analysis for the new project. The modeling analysis evaluated the potential emissions of the all the new emission point associated with this project along with the emissions from existing installations surrounding the Southwest Power Station.

Finally, the existing equipment at the Southwest Power Station consists of a 1,810 lb/mmBtu coal fired boiler and two twin-pac turbine generators. The twin-pac generators were installed in 1982 and are capable of combusting pipeline grade natural gas and fuel oil number 2. The coal fired boiler was installed in 1976 and has been operated as a baseload unit for the majority, if not all, of that time. As a baseload unit, the boiler is operated year round except for a small period of time where it is taken off-line for scheduled maintenance and repair. The percent load in which the boiler operates might fluctuate throughout a day, but the boiler would still be in operation the whole time.

The following comments were presented to the Air Pollution Control Program during testimony during the public hearing. The comments will be paraphrased below due to the length of the comments. The original comments may be read in full in the Attachments.

Comments from Ruth Bamberger, representing League of Women Voters:
City Utilities failed to develop a diversified energy portfolio that includes a mix of energy efficiency technologies and renewable energy and are not adding controls for mercury or carbon dioxide.

City Utilities Response:
No Response.

Air Pollution Control Program's Response:
Although the Air Program appreciates the League of Women Voters' comments and participation in the public participation process, we lack the regulatory authority to make any of the changes recommended. Please see the response to the Sierra Club's comment for further details on mercury.

Comment from Stan Van Velso, representing Soutwest Missouri Citizens for Clean Energy:
The BACT analysis performed by City Utilities and reviewed by DNR does not follow the federal guidelines. City Utilities did not choose the lowest available emission limits for NO_X, SO_2, PM and mercury.

City Utilities Response:
No Response.

Air Pollution Control Program's Response:
The emission limits for BACT are set after a complete and thorough BACT review. As stated previously, BACT is a case-by-case determination and just because "Source A" has an emission limit of X, this emission limit is not automatically the BACT limit ini future projects. There are many different considerations taken into account when determining the appropriate BACT emission limit for a project. For a detailed response on the Air Program's BACT analysis, please see the previous responses on this issue.

Comment from Stan Van Velso, representing Soutwest Missouri Citizens for Clean Energy:
Coal washing was improperly eliminated from the BACT analysis.

City Utilities Response:
No response.

Air Pollution Control Program's Response:
Please see the Air Program's response to Sierra Club's comment on this issue.

Comment from Dr. Gary Wright
Comments were received in writing and then testimony during Public Hearing:

1. How much mercury will be emitted by the new plant?
2. With EPA rules on mercury being disputed, what contingency plan does CU have fore retrofitting the new plant if stringent controls are enacted?
3. How will CU reduce emissions from the James River plant which CU admits is obsolete and heavily polluting? How will that be paid for?
4. Wont sale of "excess power" produced in the early years of the new plant increase use of the James River plant?

City Utilities Response:
No response.

Air Pollution Control Program's Response:
The Air Program calculated potential uncontrolled mercury emissions associated with the new coal fired boiler to be approximately 180 pounds per year. Once the boiler is fully operational, the permit requires City Utilities to conduct stack testing to obtain site specific emission factors in order to more accurately predict mercury emissions. The stack testing will also be used to demonstrate compliance with the mercury emission limitation found in the permit. If the stack testing demonstrates that the emission factor used in calculating potential mercury emissions in the permit, the City Utilities will have to submit a new evaluation to the Air Program for review.

City Utilities will have to comply with all future applicable mercury regulations. It is the Air Program's understanding that City Utilities does plan on installing an activated carbon injection system in anticipation of probably future legislation. In fact, emission point such as hauling and

storage of the activated carbon were included in the modeling analysis conducted by the Air Program.

The permit being issued involves the new coal fired boiler at the existing Southwest Power Station and does not involved the James River Station. Based upon future legislation City Utilities will have to determine the best mercury control options at the James River Station. In addition, the Air Program does not have the authority to regulate the business decisions on how each plant, James River or Southwest, is operated as long as the operations meet the requirements of their specific air permits.