## SCR Availability – Single Unit Review

- Unit operation more stable after first season
- Determine effective "12 month" estimate from average data 2003 to 2005

| Year | 1 hour average | | 3 hour rolling average | | 24 hour rolling average | |
|---|---|---|---|---|---|---|
| | Average | Std Dev | Average | Std Dev | Average | Std Dev |
| 12 Month (ppm) | 31.00 | 5.85 | 31.00 | 5.07 | 31.00 | 3.67 |
| 12 Month (#/mmbtu) | 0.054 | 0.001 | 0.054 | 0.00088 | 0.054 | 0.00064 |

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## SCR Availability – Single Unit Review

- Predicted achievable $NO_x$ emissions based on effective 12 month data

| Averaging Period | Average | Confidence Intervals | | |
|---|---|---|---|---|
| | | 68% | 95% | 99.7% |
| 1 hour average (lbs/mmBtu) | 0.0540 | 0.0550 | 0.0560 | 0.0570 |
| 3 hour rolling average (lbs/mmBtu) | 0.0540 | 0.0549 | 0.0557 | 0.0566 |
| 24 hour rolling average (lbs/mmBtu) | 0.0540 | 0.0546 | 0.0553 | 0.0560 |

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## SCR Availability – Conclusions

- 90% NOx removal achieved by ~10,000 MW
- Outlet emissions on less than 0.05 lbs/mmBtu achieved by multiple units
- Availability insensitive to catalyst type, all types have achieved 90%
- Availability insensitive to ammonia type, all types have achieved 90%
- Arrangement type appears to affect, mostly due to sample size

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## SCR Availability – Conclusions, Cont.

- SCR system supplier appears to effect availability, not all have units achieving 90%
- Single unit review suggests
  - Plants can and have learned operation
  - Once plant operation stable it remains stable
  - Stable units can repeatable provide low standard deviations of outlet emissions rates
  - Achievable $NO_x$ emissions rates with >99% confidence < 0.06 lbs/mmBtu

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## Mechanical Design

- Establish Design Conditions
- Applicable Codes and Standards
- Project Specific Requirements and Challenges



## Design Conditions

- Dead Loads – Weight of system and all permanently attached material
- Live Loads - Not permanently attached loads
- Environmental Loads
  - Wind
  - Snow
  - Seismic
- Operating and Excursion Loads
  - Pressure (Operating ± 20 iwc, Excursion ± 35 iwc)
  - Temperature (Operating 650 – 750 °F, Excursion 800 ° F)
  - Ash (18" deep at 60 lbs/ft$^3$)

## Codes and Standards

- American Institute of Steel Construction (AISC)
  - Manual of Steel Construction
- Local and National Building Codes
- American Society of Civil Engineers (ASCE)
  - The Structural Design of Air and Gas Ducts for Power Stations and Industrial Boiler Applications
- Institute of Clean Air Companies (ICAC)
  - Structural Design Guideline for SCR Reactor Casings





## Project Requirements and Challenges

- Existing Support Structure Integration
  - Existing Design Information
  - New Code Requirements
- New Duct System in Tight Spaces
- Minimize Ash Layout
- Meet Velocity Requirements (25 to 50 ft/s)
- Provide Effective Catalyst Handling System

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## Construction

- Method of Shipping
  - Truck
  - Barge
- Crane Selection and Placement
  - Maximum Lift Ranges
- Site Laydown and Storage

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## Construction

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## Construction

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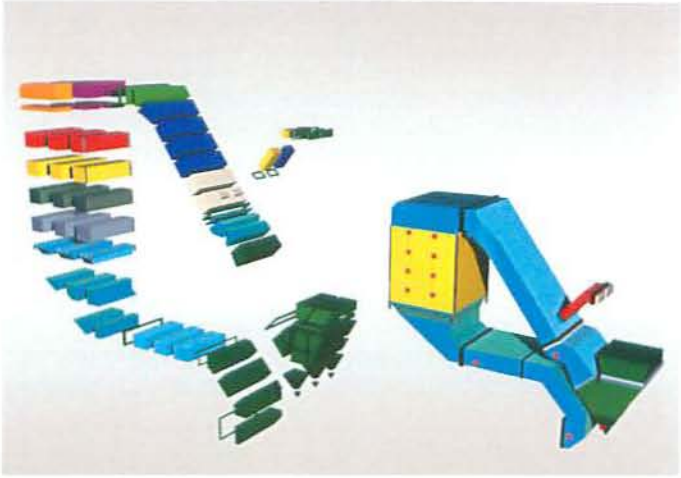
## Construction





## Construction – Catalyst Loading

## Construction – Catalyst Loading (Movie)

## Commissioning – Training

- SCR theory
- SCR process description
- Ammonia system
  - Unloading & Storage
  - Injection
- Lay-up/Dilution Air System
- Start-up and shutdown
- Catalyst handling, cleaning and management

## Commissioning – C.O.P.s

- Commissioning and Optimization Procedures for all subsystems (Ammonia Unloading & Storage, Ammonia Injection, etc…)
- Detailed "checklist" format with descriptions and tag numbers for thorough commissioning





## System Optimization - Goals

- Verify System / Reactor Inlet Conditions
- Outlet $NO_x$ Distribution Near Uniform
- $NH_3/NO_x$ Profile < 5.0% Std Dev
  - < 3.0% Std Dev Optimal

## System Optimization – Influence Testing

- Insight into ammonia distribution
- Aids in injector tuning
- Influences can be simulated in the flow model for comparison

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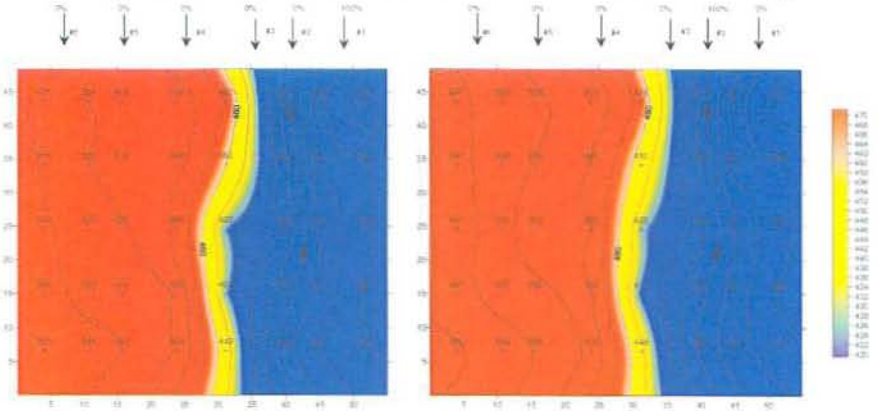
## System Optimization – Influence Testing



Valve 1 Valve 2

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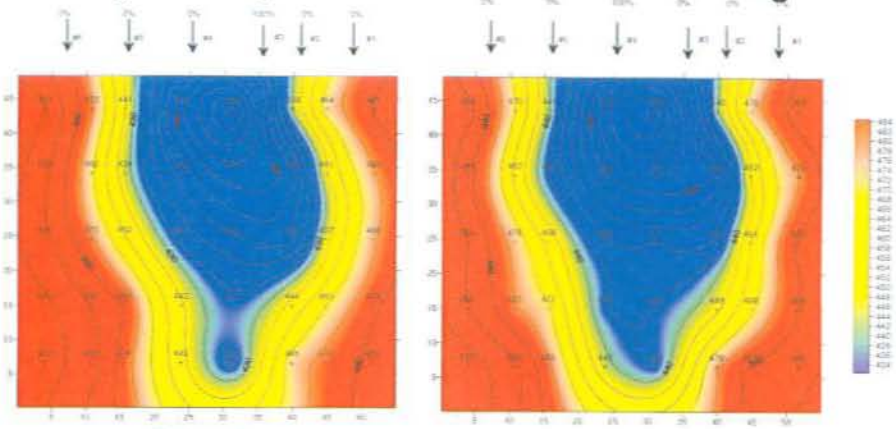
## System Optimization – Influence Testing



Valve 3 Valve 4



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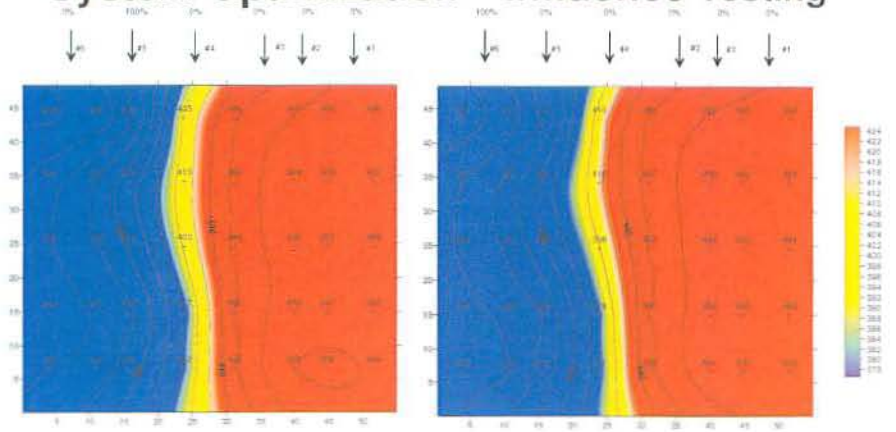
## System Optimization – Influence Testing



Valve 5 Valve 6

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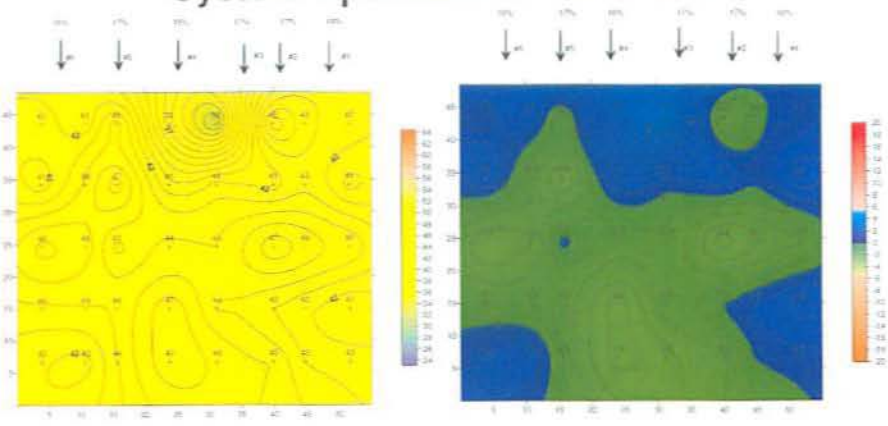
## System Optimization – Results



Outlet $NO_x$ $NH_3/NO_x$



## System Testing – Inlet Condition Verification

- $NO_x$ Inlet
- Temperature
- $SO_3$

## System Testing – Grid Average vs Analyzers

- Analyzer location may not be indicative of grid average
- Inlet not sensitive (i.e.: Ave 300 ppm, Analyzer: 290 ppm)
- Outlet is sensitive (i.e.: Ave 30ppm, Analyzer: 20 ppm)
- Solution: Operating curve for new set points

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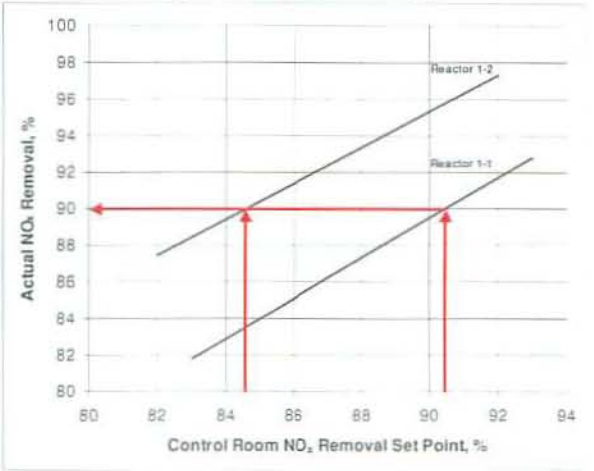
## System Testing – Grid Average vs Analyzers

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## System Testing – $SO_2$ to $SO_3$ Conversion

- Conversion changes with temperature, $SO_2$, $O_2$, & gas flow
- Need to correct to design conditions using vendor supplied curves
- Measurement by controlled condensation



## System Testing – Pressure Loss

- Static measurements need to be corrected for:
  - Mass Gas Flow
  - Temperature
  - Elevation
- Need to correct ductwork separate form catalyst
  - Laminar vs Turbulent Flow
- Corrections derived from Bernoulli Equation

$$\frac{P}{\rho} + \frac{v^2}{2} + g \cdot z = H$$

## System Testing – Pressure Loss (cont')

- For ductwork, flow and temperature are corrected by modifying the Bernoulli terms for velocity

$$\frac{\Delta P_1}{\Delta P_2} = \frac{\rho_1 \cdot v_1^2}{\rho_2 \cdot v_2^2} \quad \Rightarrow \quad \frac{\Delta P_1}{\Delta P_2} = \frac{m_1^2 \cdot T_1 \cdot A_2}{m_2^2 \cdot T_2 \cdot A_1}$$

Where:

$\Delta MW_{FG}$ is negligible

Density change due to pressure loss is negligible (for now)

Temperature is in absolute temperature units

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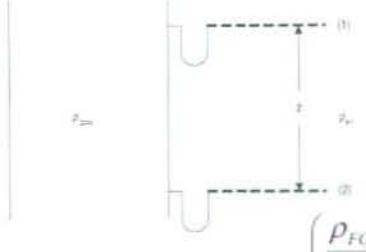
## System Testing – Pressure Loss (cont')

- For ductwork, the elevation must be corrected as there are different ambient forces:



$$\Delta P_{Elevation} = \Delta P_{Barometric1-2} + z \cdot \frac{\left(\frac{\rho_{FG@1} + \rho_{FG@2}}{2}\right)}{\rho_{H2O}}$$

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## System Testing – Pressure Loss (cont')

- To correct ductwork:
  - Calculate $\Delta P_{Elevation}$ and add to the measured value
  - Use elevation adjusted $\Delta P$ as $\Delta P_1$ in flow and temperature correction
  - Find $\Delta P_2$ which will be corrected for all variables





## System Testing – Pressure Loss (cont')

Example:

Flue Gas pressure drop measured at 1 iwc from static pressures at two elevations (No change in area of the duct)

Elevation 1 = 500 ft above sea level ($P_{Barometric}$ = 399.74 iwc)
Elevation 2 = 450 ft above sea level ($P_{Barometric}$ = 400.45 iwc)
Flue Gas Density @ 1 = 0.0315 lbs/ft$^3$
Flue Gas Density @ 2 = 0.0314 lbs/ft$^3$
Flue Gas Mass Flow Design = 2,000,000 lbs/hr
Flue Gas Mass Flow Measured = 2,200,000 lbs/hr
Flue Gas Temperature Design = 700 °F
Flue Gas Temperature Measured = 740 °F

## System Testing – Pressure Loss (cont')

Example:

$$\Delta P_{Elevation} = \Delta P_{Barometric} + (z_1 - z_2) \cdot \frac{\frac{(\rho_{FG1} + \rho_{FG2})}{2}}{\rho_{H2O}}$$

$$\Delta P_{Elevation} = (399.74 - 400.45) + (500 - 450) \cdot 12 \cdot \frac{\frac{(0.0315 + 0.0314)}{2}}{62.43}$$

$$\Delta P_{Elevation} = -0.41\ iwc$$

$$\Delta P_{Corrected} = 1 - 0.41 = 0.59\ iwc$$

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## System Testing – Pressure Loss (cont')

Example:

$$\Delta P_{Corrected,Flow} = \Delta P_{Corrected,Ele} \cdot \frac{m^2_{Design}}{m^2_{Measured}}$$

$$\Delta P_{Corrected,Flow} = 0.59 \cdot \frac{2{,}000{,}000^2}{2{,}200{,}000^2}$$

$$\Delta P_{Corrected,Flow} = 0.59 \cdot 0.826$$

$$\Delta P_{Corrected,Flow} = 0.49\ iwc$$

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## System Testing – Pressure Loss (cont')

Example:

$$\Delta P_{Corrected,Temp} = \Delta P_{Corrected,Flow} \cdot \frac{T_{Design}}{T_{Measured}}$$

$$\Delta P_{Corrected,Temp} = 0.49 \cdot \frac{(700+459.67)}{(740+459.67)}$$

$$\Delta P_{Corrected,Temp} = 0.49 \cdot 0.967$$

$$\Delta P_{Corrected} = 0.47\ iwc$$

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## System Testing – Pressure Loss (cont')

- For catalyst corrections, vendors supply correction curves to be used
  - Mass Flow & Temperature
  - Volumetric Flow
- Elevation needs to be corrected. Same formula as the ductwork

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## System Testing – Velocity & Flow Angle Distributions

- Proven during model study only
- Reactor velocity too low for pitot tube measurement
- Flue gas environment not acceptable for hot wire anemometer





## System Testing – $NH_3/NO_x$ Distribution

- Calculated from Inlet & Outlet $NO_x$ Grids
- Calculate for every point on outlet
- Good Distributions < 5% Std Dev over grid
- Optimal Distributions < 3% Std Dev over grid
- Formula:

$$\frac{NH_3}{NO_X} = \left( \left( \frac{NOx_{INLET\,AVE} - NOx_{OUTLET\,POINT}}{NOx_{INLET\,AVE} - NOx_{OUTLET\,AVE}} \right) - 1 \right) \cdot 100$$

  - Variation > 0 excess ammonia, < 0 excess $NO_x$

## System Testing – $NH_3/NO_x$ Distribution

Example:

Inlet $NO_x$ Average: 300 ppm @ 3% $O_2$

Outlet $NO_x$ Point: 23 ppm @ 3% $O_2$

Outlet $NO_x$ Average: 28 ppm @ 3% $O_2$

$$\frac{NH_3}{NO_X} = \left(\left(\frac{NOx_{INLET\,AVE} - NOx_{OUTLET\,POINT}}{NOx_{INLET\,AVE} - NOx_{OUTLET\,AVE}}\right) - 1\right) \cdot 100$$

$$\frac{NH_3}{NO_X} = \left(\left(\frac{300-23}{300-28}\right) - 1\right) \cdot 100$$

$$\frac{NH_3}{NO_X} = 1.84$$

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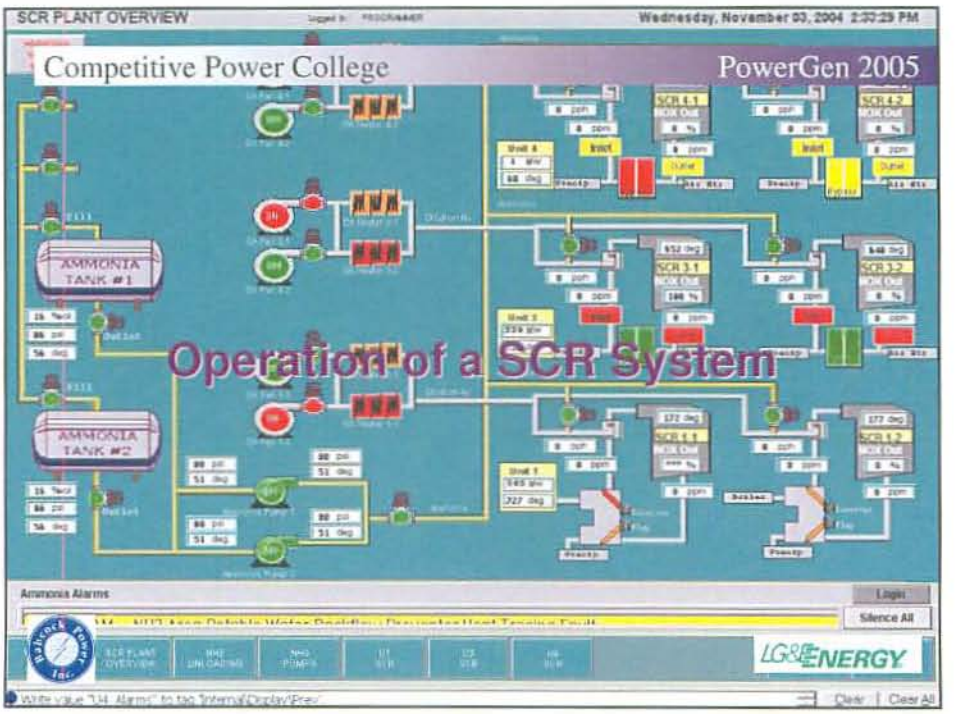
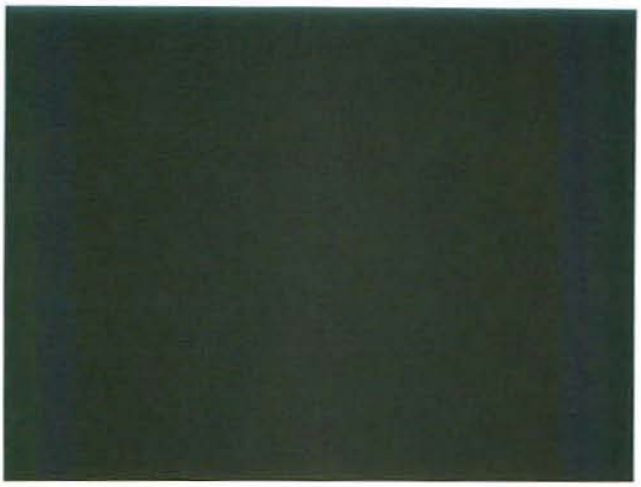


## SCR Start-Up – Full Bypass (Movie)



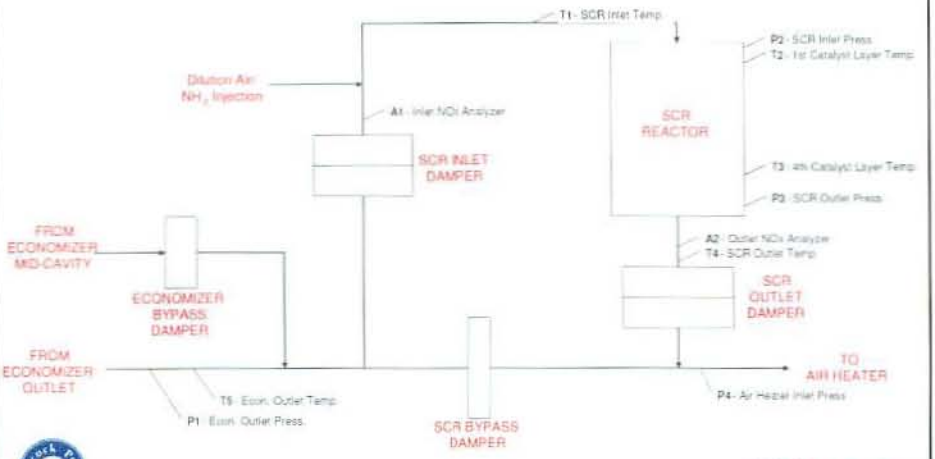




## SCR Start-Up Requirements

- Oil Firing
  - Typically used during low loads for startup
  - SCR Reactor must be isolated from the flue gas flow
- Catalyst Protection
  - Temp. Ramp Rate
  - Moisture condensation
  - Ammonia bisulfate formation

## SCR Reactor Schematic



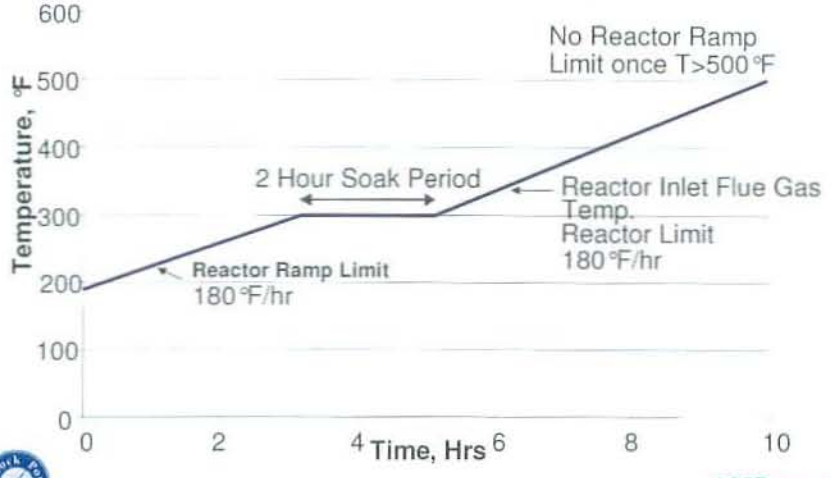





## SCR Start-Up Requirements

- Below T= 500 °F,
  - Use Max. Ramp Rate DT/dt ≤ 3 °F/min
    - SCR Reactor Steel Structure DT/dt ≤ 3 °F/min or 180 °F/hr
    - Catalyst DT/dt < 18 °F/min or 1080 °F/hr
  - Required "Thermal Soak Period"
    - 2 hrs once T1 (SCR Inlet Temp.) ≥ 300 °F (approx.)
    - Wait for T3 (SCR Outlet Temp.) ≥ 300 °F (approx.)
    - Thermal soak temperature is above sulfuric acid dew point

## SCR Temperature Ramp-Up Rates

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## SCR Start-Up Operating Modes

- Cold Reactor- Pre-Warm
  - Ave. Catalyst Temp. < 150°F
  - Must Pre-warm reactor with Dilution/Layup Air
- Warm Reactor
  - Ave. Reactor Temp. > 150°F
  - Must warm reactor using Flue Gas and Dilution/Layup Air
- Hot Reactor
  - Ave. Reactor Temp > 500°F
  - Can be placed in service with $NH_3$ Injection when Reactor Outlet Flue Gas Temperature Above Minimum Continuous Operating Temp.
- Operate Both Reactors as One, All Damper Positions Should Be Same On Both Reactor During Startup and Shutdown

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## SCR Start-Up Procedure – Cold Reactor

Using Dilution/Layup Air-

- For Layup Mode
  - Warm above 150°F to prevent moisture accumulation during extended periods with SCR off-line (non-OTAG)
- For SCR Startup
  - Warm to approx. 200°F to 300°F
- Allow dilution air to exit the reactor through the leakage of the SCR Outlet Damper with seal air off

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## SCR Start-Up Procedure – Cold Reactor

- Step 1: Close seal air shutoff valve on SCR outlet damper
- Step 2: Set control temp. setpoint of dilution air= 300, typical setpoint for layup 200 °F
- Step 3: Start both Dilution Air Fans and steam coils, operator choice
- Step 4: Wait for T3(SCR Outlet Temp.) > 150°F (for Layup Mode) or approx. 200 to 300°F (for SCR startup)

## SCR Start-Up Procedure – Warm Reactor

- Step 1: Open SCR Outlet Damper
  - Damper Opens 2.5% with 3 min. wait periods
- Step 2: Once Reactor reaches 280 °F to 320 °F
  - Hold damper position for 2 hours for thermal soak
- Step 3: Continue Opening SCR Outlet Damper
- Step 4: Open SCR Inlet Damper to control reactor and catalyst warmup at DT/dt $\leq$ 180 °F/hr.
  - Damper Opens 2.5% with 3 min. wait periods
- Alarms/Interlocks for all Damper Movements
  - 150 °F/hr High Alarm- Hold Damper Positions
  - 180 °F/hr High High Alarm
  - Furnace Pressure, use current plant alarm signal

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## SCR Start-Up Procedure – Warm Reactor

Once SCR Inlet and Outlet Dampers are open to 100%

- Step 5: Gradually close SCR Bypass Damper to force flue gas through reactor
- Step 6: Close SCR Bypass Damper 100%
- Step 7: Open Seal Air Shutoff valve for SCR bypass dampers
- Step 8: Continue to warm up reactor until reactor inlet and outlet temperatures > $T_{mcot}$
- Step 9: SCR System is ready for $NH_3$ Injection

## SCR Shutdown Procedure

- SCR sootblowers (if installed) must run a complete cleaning cycle to remove accumulated ash from catalyst
- Shutdown Options
  - SCR and boiler is shutdown if any work or service is performed on the SCR
  - SCR can be placed in Layup Mode





## SCR Shutdown Procedure

- Step 1: Cycle Sootblowers for full cleaning cycle to remove any ash accumulation
- Step 2: Terminate $NH_3$ Injection
- Step 3: Maintain flue gas flow through SCR until Inlet $NO_x$= Outlet $NO_x$ concentration (+/-5%) to remove residual ammonia on catalyst, use stack CEMS if SCR outlet meter out of scale and inlet $NO_x$ meters.

## SCR Shutdown Procedure

**For Layup Mode**

- Step 4: Open SCR Bypass Dampers to 100%
- Step 5: Close SCR Inlet Dampers completely
- Step 6: Close SCR Outlet Dampers completely
- Step 7: Scavenge SCR with warm dilution air
- Use leakage across SCR Outlet damper to avoid overpressure of the reactor.

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## SCR Shutdown Procedure

**For Boiler and SCR Out of Service**

With Bypass Dampers Closed-

- Purge Boiler and SCR for 5 mins. (per NFPA) using FD/ID Fans

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## SCR Economizer Bypass Operation

**For Reduced Boiler Loads**

**Based on SCR Inlet Temperature Economizer Bypass Opens**

- LOW, LOW LOW alarms to operator, LOW TRIP of ammonia
- Operator Controllable in Manual Mode
- Automatic Control with Position Controlled by Feed Forward Loop Based on Boiler Load. Final function of position vs. boiler load determined during startup.

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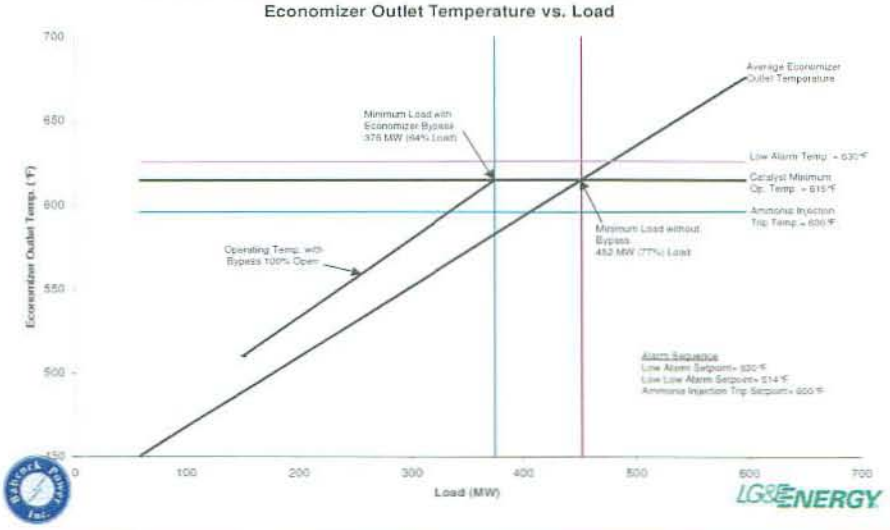
## SCR Economizer Bypass Operation

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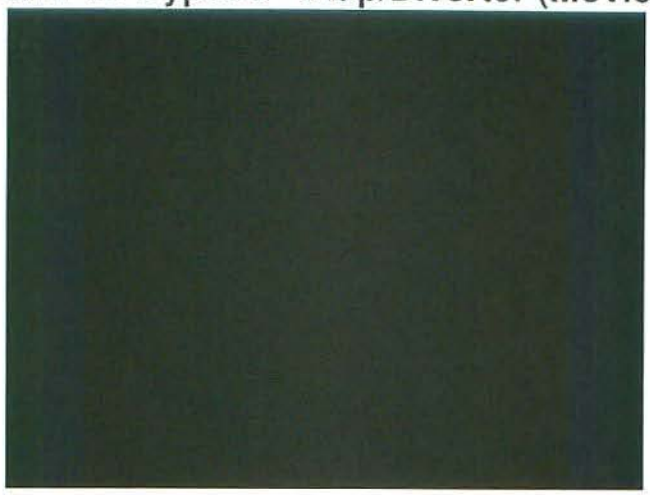
## SCR Full Bypass – Flap/Diverter (Movie)



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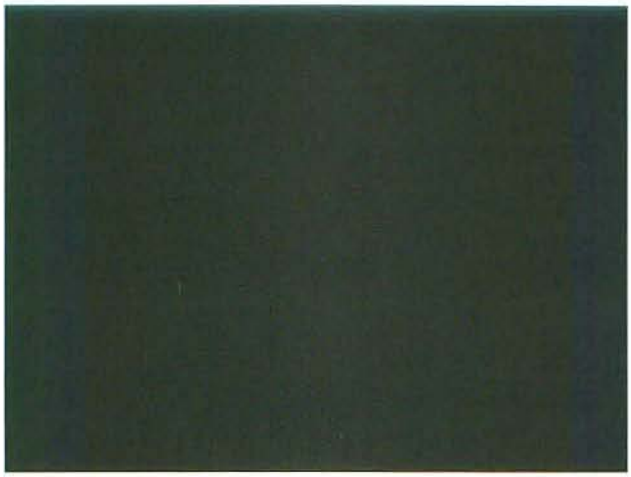
## SCR Start-Up – No Bypass (Movie)



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## SCR Maintenance

- Ammonia System
  - Pumps
  - Injection System
  - Detectors
- Dilution and Seal Air System
  - Fans
  - Steam/Water Coils
- Dampers
- $NO_x$ Analyzers
- Catalyst Cleaning

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## SCR Maintenance – Ammonia System

- Pumps
  - Orifice based flow control
    - Poor results
    - Pump often vapor bound and had multiple cavitation trips
  - Constant differential pressure control
    - Good results
    - Pump was extremely sensitive to alignment and line strain
    - To alleviate strain, pipes and supports laser aligned
- Ammonia Injection Valves
  - Equal percentage trim did not accurate control $NH_3$ flow
  - Linear trim produced better results



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## SCR Maintenance – Ammonia System

- Ammonia Detectors
  - Detectors have a 12 month shelf life
  - After life has expired, detector tends to fail often leading to ammonia trips on the units
  - Institute a preventative maintenance plan
    - All sensors to be changed prior to ozone season
    - Detectors are calibrated at the end of the season (5 – 6 months)
    - Replaced again prior to the season (12 months)

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## SCR Maintenance – Dampers

- Many jobs have had problems with dampers "sticking"
  - Initial torque setting was too low
  - Once increased, operation was normal
- Location of the damper electronics important
  - If too hot, actuators tend to fail
- For jobs with economizer bypass, the initial setting was often too high
  - Economizer bypass and back-pressure damper curves revised
  - SCR start-up trends revised based on actual temperatures

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## SCR Maintenance – $NO_x$ Analyzers

- In-situ Analyzers
  - Tend to require frequent manual recalibration
  - Filters wear fast in high dust applications
  - Need to be located well as temperature affects operation
- Dilution Extraction Analyzers
  - More reliable than In-situ
  - Shelter provides optimal analyzer operating conditions
  - Automatic calibration cycle sufficient for consistent readings

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## SCR Maintenance – Catalyst Cleaning

- Sootblowers
  - Require steam as cleaning media
  - Need to ensure steam quality at the rakes to avoid "wet" steam
- Sonic Horns
  - Keep ash moving rather than "cleaning" the catalyst
  - Use a low level of pressurized air
  - More cost effective than sootblowers

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# Thank You

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# UTILITY E-ALERT

**#798 – November 3, 2006**

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## COAL – U.S.

- *Monticello Draft Permit Hearing November 27*
- *Shaw Stone & Webster to Provide Construction Labor Services for Gorgas FGD*
- *Duke Expects Higher Costs for New Coal-fired Units at Cliffside*
- *Arguments Presented to Supreme Court in Duke NSR Case*
- *Hearings Held on Permit for Sunflower Electric's Proposed 2,100 MW Power Plant*
- *Fuel Tech Awarded NOxOUT Orders Totaling $4.0 Million*
- *FreightCar America Receives Big Order for Coal Railcars for the New TXU Plants*
- *PPL Reports FGD Construction on Budget*
- *DPL Reports Capital Expenditures in 2006 Relating to FGD Construction*

## COAL – WORLD

- *Duchting FGD Pump Orders*
- *BHEL Proposing IGCC Projects for India*
- *AES to Build Coal-fired Power Plant in Chhattisgarh*
- *Morocco Plans $1.5 Billion 1,320 MW Coal-fired Power Station*
- *B&W Canada/Air Liquide to Develop "Oxyfuel" Technology for SaskPower 300 MW Clean Coal Power Plant*
- *PLN/AES Plan 1,200 MW Coal-fired Power Plant in South Sumatra*
- *Cormetech to Supply Catalyst for Pego 1 and 2*

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  - **300 MW Wind Farm Project at Tulufan Approved**
  - **Six Large Wind Farms will be Constructed in Fujian Province**
- *Nuclear*
  - **6,000 MW Nuclear Power Plants Planned at Rushan and Yueyang (China)**
- *Coal*

- **300 MW FGD at Datang Huxian No 1 Begins Operation**
- **300 MW FGD at Zhuzhou 4 in Operation**
- **2 x 300 MW FGD at Huadian Neijiang in Operation**
- **2 x 200 MW FGD at Huadian Huangjiaozhaung Begins Operation**
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- **700 MW FGD at Zhuhai No. 1 Begins Operation**
- **SCR Construction Finished at 600 MW Ninghai No. 5**
- **ESP-FF Retrofit on a CFB Boiler**
- **New Units Begin Operation**

## GAS/OIL – U.S.

- ***Sargent & Lundy is Design Engineer for Xcel Riverside Repower***

## GAS/OIL – WORLD

- ***E.ON to Build 1,200 MW Combined Cycle Power Plant at Grain***

## ETHANOL/GASIFICATION

- ***Indiana Gasification to Build $1.5 Billion Plant***
- ***Gasification/$CO_2$ Removal Demonstration Project in Queensland, Australia***
- ***Natural Gas or Coal for Ethanol Plants***

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- ***Toshiba Completes Acquisition of Westinghouse Electric***
- ***Atmostryexport to Build 2 x 1,000 MW Nuclear Power Plant in Bulgaria***

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- ***Xcel Looks to Hydroelectric and Wind Power***
- ***Indiana Michigan Power Discussing Wind Farms***
- ***GE Turbines for Su Jia He Kou Hydroelectric Plant in China***

## HOT TOPICS

- ***Haldor Topsoe Catalyst Efficiency Revisted***
- ***$PM_{2.5}$ Hot Topic Hour Reveals that Firm Guarantees are being made based on Questionable Monitoring Methods***
- ***Hot Topic Discussion of Spray Dryer vs. CFB FGD November 9***

## SCHEDULE FOR FUTURE HOT TOPIC HOURS

## ACCESSING ALL THE PROJECTS AND INFORMATION ONLINE

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## COAL – U.S.

***Monticello Draft Permit Hearing November 27***

**TXU Generation Co.**'s proposal for expansion (800 MW) at its coal-fired Monticello power plant has received a draft permit from the **Texas Commission on Environmental Quality** (TCEQ). Public comments are being accepted by TCEQ on the air quality permit through November 16. The **State Office of Administrative Hearings** will conduct a public hearing on November 27 in Mount Pleasant.

***Shaw Stone & Webster to Provide Construction Labor Services for Gorgas FGD***

**Shaw Stone & Webster** will provide construction labor services to install FGD equipment on three units at **Southern Company** Gorgas. Shaw will also perform boiler maintenance services to support the associated outages.

***Duke Expects Higher Costs for New Coal-fired Units at Cliffside***

**Duke Energy** anticipates the cost to add two 800 MW coal units at Cliffside to exceed the $2 billion previously estimated. The first unit is scheduled to commence operations in 2011. The estimated degree of cost increases was sufficient enough such that Duke decided to file the increases with the **North Carolina Utilities Commission** on a confidential basis. The cost increases are based on bids that represent about 20 percent of the construction costs.

***Arguments Presented to Supreme Court in Duke NSR Case***

Environmental groups and the Bush administration defended a Clinton-era clean air program Wednesday in the Supreme Court, arguing that a power company must install pollution controls on its aging coal-fired plants. A lawyer representing **Duke Energy Corp**. said government regulators suddenly switched their interpretation of 26-year-old federal rules and sued the company six years ago. Lawyers for the environmental groups and the government said Duke and other utilities long ago understood federal requirements and chose not to comply with them. The outcome of the case, Environmental Defense vs. Duke Energy Corp., could affect power plants in 10 states where utility companies are challenging federal requirements under the New Source Review program. At issue is whether the **4th U.S. Circuit Court of Appeals** had the authority to handle the case when it ruled in favor of Duke. Also in dispute is whether emissions should be calculated hourly, as Duke wants, or annually, as the environmental groups and **EPA** say.

***Hearings Held on Permit for Sunflower Electric's Proposed 2,100 MW Power Plant***

Charles Benjamin, an attorney for the **Sierra Club**'s Kansas chapter, said **Sunflower Electric Power Corp**. is likely to overcome misgivings about potential environmental problems for its proposed 2,100 MW Holcomb/Sand Sage power project because the utility is promoting its plan as economic development. The new plants would be built near Sunflower's existing 350 MW station south of Holcomb, Kansas. The **Kansas Department of Health and Environment** (KDHE) has drafted a proposed permit for the project. The agency had a hearing Thursday in Topeka, attended by about 100 people. KDHE had a hearing Tuesday in Garden City and plans to have a third one November 16 in Lawrence. It will take written testimony until November 30 and expects to decide whether to issue the permit by January.

***Fuel Tech Awarded NOxOUT Orders Totaling $4.0 Million***

**Fuel Tech, Inc**. has three orders for air pollution control projects totaling $4.0 million. Placed by a Southeastern utility alliance partner, the orders largely represent the installation phase of four NOxOUT® SNCR projects on coal-fired boilers at three separate plant locations.

***FreightCar America Receives Big Order for Coal Railcars for the New TXU Plants***

**FreightCar America, Inc**. has entered into an agreement with **TXU Generation Development Company LLC** to be TXU's exclusive supplier of up to 7,650 aluminum AutoFlood III™ coal-carrying railcars to be delivered in the second half of 2008 through 2009. TXU's actual requirements may change at TXU's discretion, depending chiefly on the timely permitting of its new generating units in the Electricity Reliability Council of Texas power grid. TXU is expanding its power generation capacity by adding production units at its Monticello, Martin Lake, Big Brown, Tradinghouse, Lake Creek, Valley, and Morgan Creek sites in Texas.

***PPL Reports FGD Construction on Budget***

As previously announced, **PPL** has begun construction of $1.5 billion in pollution-control equipment at coal-fired power plants in Pennsylvania, including sulfur dioxide scrubbers at both units of its Montour power plant and at all three units of its Brunner Island power plant. The scrubbers for both Montour units and Unit 3 at Brunner Island are expected to be in service during 2008, and the scrubber for Units 1 and 2 at Brunner Island is expected to be in service during 2009. Scrubber construction continues to proceed on budget and on schedule.

***DPL Reports Capital Expenditures in 2006 Relating to FGD Construction***

**DPL** reports capital expenditures of $283.9 million for the first nine months of 2006 and $138.2 million for the first nine months of 2005. Total capital additions are expected to

approximate $365 million in 2006 primarily related to DPL's FGD construction program at JM Stuart and Killen.

## COAL – WORLD

### *Duchting FGD Pump Orders*

**Duchting Pumpen** is supplying pumps for the following FGD projects.

| Order Date | Project | Country |
|---|---|---|
| 7/2006 | Jiangyin Ligang | China |
| 5/2006 | Baishan | China |
| 3/2006 | Datang Panshan | China |
| 4/2005 | Ruien | Belgium |
| 1/2005 | Emile Huchet and Gardanne | France |

### *BHEL Proposing IGCC Projects for India*

**Bharat Heavy Electricals Ltd**. (BHEL) has proposed a 400 MW IGCC power plant. BHEL has also proposed to set up a 125 MW IGCC demonstration project in association with the public sector **National Thermal Power Corporation Ltd**. (NTPC). The 125 MW project, estimated to cost Rs900 crore, would be set up near NTPC's Auraiya gas-fired power plant in Uttar Pradesh, India. BHEL would commission the project while NTPC would own and operate it. "We have submitted a feasibility report and are awaiting approvals for the 125 MW IGCC project. Simultaneously, we are also preparing a blueprint for a 400 MW IGCC plant that would be run on a commercial basis," BHEL chairman and managing director A.K. Puri said.

### *AES TO Build Coal-fired Power Plant in Chhattisgarh*

The India government on Thursday approved $370 million in foreign direct investment in a coal-fired power project in the state of Chhattisgarh to be funneled through a local unit of U.S.-based **AES Corp**.

### *Morocco Plans $1.5 Billion 1,320 MW Coal-fired Power Station*

Morocco's **National Electricity Office** (ONE) is launching a pre-qualification tender for a $1.5 billion coal-fired power station as part of a drive to expand electricity production. The coal-fired station would consist of two units of 660 MW each, located in the Cap Rhir area, about 40 km north of the Atlantic resort of Agadir. A presentation meeting on the project is scheduled for November 24 in Casablanca and the deadline for bids is December 20, 2006, ONE said.

### *B&W Canada/Air Liquide to Develop "Oxyfuel" Technology for SaskPower 300 MW Clean Coal Power Plant*

**SaskPower** has selected the key technology to be used in the removal of carbon dioxide emissions from a proposed $1.5-billion 300 MW clean-coal power project. SaskPower, **Babcock & Wilcox Canada** and **Air Liquide** agreed to jointly develop "oxyfuel" technology. The oxyfuel process removes nitrogen from the combustion air. The gases leaving the boiler are then easier to purify, compress and liquefy for use in enhanced oil recovery (EOR) projects or underground storage. The technology could allow SaskPower to sequester 90 percent of the plant's $CO_2$—8,000 tonnes a day. If approved, the proposed 300 MW clean-coal power plant could be in service by 2011. SaskPower expects to make the decision on whether to proceed with the clean-coal power plant by mid-2007, following completion of the research on oxyfuel and other pre-commitment feasibility work.

***PLN/AES Plan 1,200 MW Coal-fired Power Plant in South Sumatra***

**PT Perusahaan Listrik Negara** (PLN) signed a preliminary deal with **AES Corp**., Japanese trading firm **Sojitz** and local firm **PT Triaryani** to build a 1,200 MW coal-fired power plant. The cost of the project, to be located in South Sumatra in the west of the Indonesia archipelago, is estimated at about $1.5 billion.

***Cormetech to Supply Catalyst for Pego 1 and 2***

**Cormetech** has been awarded a contract by **Alstom Power Sweden AB** to supply SCR for the Tejo Energia Pego Power Plant. Alstom Power Sweden AB will be providing the DeNOx system for the 628 MW power plant which will utilize Cormetech's new 6.9 mm pitch, 22-cell high performance SCR catalyst. The SCR installation was driven by the EU's Large Combustion Plant Directive (LCPD). The Alstom contract will mark the fourteenth European installation for Cormetech.

## CHINA

***Renewable Energy***

**105 MW Jiangsu Rudong Wind Farm in Operation**

The Jiangsu Rudong wind farm has recently begun operations with about 70 wind units of 1.5 MW. The total designed power for this farm is 600 MW, and construction has been scheduled in three phases. **GE Energy Co.** won the contract for 100 units of 1.5 MW in the phase II construction, and all these units were installed in Shenyang in Liaoning province. It has been estimated that about 1,500 MW of wind power will be in operation in Jiangsu by 2010; this will be about 20 percent of the wind power in China at that time.

**300 MW Wind Farm Project at Tulufan Approved**

**Guodian Energy Co.** has an agreement with the government of Tulufan City for a 300 MW wind farm project. The investment is 2.4 Billion RMB. Construction is divided into

six phases. Besides the Tulufan wind farm, there are eight large wind regions in Xinjiang province with the potential available wind power estimated at 80,000 MW.

**Six Large Wind Farms will be Constructed in Fujian Province**

Six wind farms named Zhangzhou Liu'ao, Dongshan Aojiao, Hui'an Congwu, Changle Jiangtian, Zahngpu Gulei and Zhao'an Meiling will be constructed in the next four years in Fujian province. The overall power of these new units is over 600 MW, and the total investment is more than 10 billion RMB. At present, four provinces including Fujian, Guangdong, Inner Mongolia and Xinjiang, are considered the renewable energy demonstration regions, and the **World Bank** will provide loans to these projects.

***Nuclear***

**6,000 MW Nuclear Power Plants Planned at Rushan and Yueyang (China)**

A 6,000 MW nuclear power plant will be constructed at Yueyang in Hunan province. The construction is divided into three phases with a total investment of 60 billion RMB. The Chinese **State Department** has definite plans to install some nuclear power plants in the inland provinces.

China will build a 6 x 1,000 MW nuclear power plant on its northeast coast in Shandong province. The facility will be built in Rushan before 2015, the government's *Xinhua News Agency* said, by **China Nuclear Engineering and Construction Corp**., which will own 51 percent of it, along with three other companies.

***Coal***

**300 MW FGD at Datang Huxian No 1 Begins Operation**

A 300 MW FGD system for Unit 1 at **Datang** Huxian Second Power plant was put into operation on October 30, 2006. The FGD contract was awarded to **Shandong Sanrong Environmental Engineering Protection Co.** in July 2005. The FGD system employs wet limestone/gypsum technology, and the tested removal efficiency of $SO_2$ is over 95 percent.

**300 MW FGD at Zhuzhou 4 in Operation**

**Datang** Zhuzhou Power plant began operation of a 310 MW FGD system for Unit 4 on October 29, 2006. The FGD contract was awarded to **Shanghai Longking Environmental Protection Co.** in October of 2005. The FGD system is wet limestone/gypsum technology, which is licensed by Germany **LLB Co.** The $SO_2$ removal efficiency was measured to be over 98 percent. The suppliers of the main components of the FGD system are as follows: Slurry pumps--**Jiangsu Feixiang Pump Manufacture Co.**, Screw Air compressors--**Shanghai Fushi Industry Co.**, Wet limestone ball milling-

-**Jinan Heavy Industry Co.**, Adjustable blower--**Shanghai Blower Plant Co.**

**2 x 300 MW FGD at Huadian Neijiang in Operation**

After a year of construction, **Huadian** Neijiang Power plant began operation of the FGD system for the two 300 MW units on October 31, 2006. The systems are wet limestone/gypsum FGD technology, and $SO_2$ removal efficiency is over 95 percent.

**2 x 200 MW FGD at Huadian Huangjiaozhaung Begins Operation**

On October 30, 2006, **Huadian** Huangjiaozhaung (Sichuan province) power plant began operation of the FGD system for two 200 MW units. The system employs wet limestone/gypsum FGD technology, and the $SO_2$ removal efficiency is over 95 percent.

**2 x 100 MW FGD at Huadian Yibin in Operation**

**Huadian** Yibin (Hubei province) power plant began operation of FGD systems for two 100 MW units on October 29, 2006. The systems employ wet limestone/gypsum FGD technology, and the designed removal efficiency of $SO_2$ is 90 percent. **China Power Investment Yuanda Environmental Protection Co.** was the contractor for the construction.

**700 MW FGD at Zhuhai No. 1 Begins Operation**

A 700 MW FGD system at Zhuhai (Guangdong province) power plant No. 1 began operation on October 25, 2006. Another 700 MW FGD system is still under construction. The designed $SO_2$ removal efficiency is over 95 percent.

**SCR Construction Finished at 600 MW Ninghai No. 5**

The installation of a 600 MW SCR system at Guohua Ninghai (Zhejiang province) power plant No. 5 was just completed. The SCR technology is licensed by **BHK Co**. This is the first de$NO_x$ project in Zhejiang province.

**ESP-FF Retrofit on a CFB Boiler**

The particulate collector for a 480t/h CFB boiler at Huadian Wuda power plant was changed from the original ESP to the combination of ESP-FF. The dust collection efficiency increases from 99.5 to 99.99 percent. An ESP-FF (electrostatic precipitator-fabric filter) combination is regarded as a promising approach to meet stricter environmental regulations in China.

**New Units Begin Operation**

A 350 MW unit (No. 3) at **Huadian** Tengzhou Xinyuan cogeneration plant was put into operation on October 28, 2006. Another unit (No. 4, 350 MW) is under construction.

A 300 MW unit (No. 1) at **Baotou Power Co**. was put into operation on October 27, 2006. Another one (No. 2, 300 MW) is under construction.

A 125 MW unit (No. 1) at **Huadian** Changji cogeneration plant was put into operation on October 26, 2006.

Huaneng Yangxun power plant began to operate Unit 5 (600 MW) on October 23, 2006. Unit 6 (600 MW) is still under construction. Units 1-4 are each 300 MW.

## GAS/OIL – U.S.

### *Sargent & Lundy is Design Engineer for Xcel Riverside Repower*

**Xcel Energy Services** has selected **Sargent & Lundy LLC** to perform the detailed design engineering for the Riverside Repowering Project. The project will replace the existing coal-fired units 7 and 8 with a natural gas combined-cycle unit. The final 2 x 2 x 1 configuration will increase the total generating capacity of the plant by approximately 80 MW, generating 480 MW upon completion.

## GAS/OIL – WORLD

### *E.ON to Build 1,200 MW Combined Cycle Power Plant at Grain*

**E.ON UK** has received approval from the **UK Department of Trade and Industry** to build a 1,200 MW combined-cycle gas turbine power plant at the site of its existing Grain oil-fired station in Kent, UK. The construction on the £350 million gas-fired station could start as early as next year, with electricity generation expected in 2009.

## ETHANOL/GASIFICATION

### *Indiana Gasification to Build $1.5 Billion Plant*

Governor Mitch Daniels of Indiana announced there are plans to build a $1.5 billion coal gasification plant that would be the first in the country to make pipeline quality natural gas from eastern coal. Several sites are being considered, and the governor said all of them are in the southwestern corner of the state. The plant is scheduled to be online in 2011.

The project is being developed by **Indiana Gasification, LLC**, and will include a methanation process to produce pipeline quality substitute natural as (SNG). It would produce 40 billion cubic feet of pipeline quality SNG annually, which is enough to supply 15 to 20 percent of Indiana's residential and commercial gas demand.

According to the letter of intent for 30-year supply contracts signed by the utilities last week, about two-thirds of the SNG produced by the new plant would be purchased by

Indiana's three largest gas utilities, **Vectren Corporation**, **NIPSCO** (Northern Indiana Public Service Company), and **Citizens Gas** to help meet residential and commercial gas demand. NIPSCO would purchase the remainder of the gas to fuel electric generation for its service territory to meet seasonal demands. The plant will use **GE Energy**'s gasification technology.

***Gasification/$CO_2$ Removal Demonstration Project in Queensland, Australia***

Queensland's (Australia) clean coal technology is being developed in three parts in central Queensland, the first being a gasification plant at Stanwell near Rockhampton, which will strip up to 80 percent of the $CO_2$ produced in current coal-production methods from the gas used to fire a power station. The second part involves transporting the expunged $CO_2$ in a pipe to the northern Denison Trough near Emerald, and the third involves burying it in an old natural gas field, reports *The Australian*. Professor Greenfield, senior deputy vice-chancellor at the **University of Queensland**, said the cost of producing power using clean coal technology was 30-50 percent higher than conventional methods. "There is no way it could be introduced in a competitive electricity market of the sort we have now, but the price signals will provide an incentive to move in this direction," he said. The project is being coordinated through Stanwell, a power generator fully owned by the Queensland Government, although personnel from **Shell** are also working on the project.

***Natural Gas or Coal for Ethanol Plants***

Des Moines' logjam over a new ethanol plant comes as the industry continues a trend toward making the fuel by burning coal, reports the *Des Moines Register*. Two companies are vying to build an ethanol plant in southeast Des Moines. One, **Lincolnway Energy** of Nevada, IA, would burn coal, as it does in its Story County plant. The other, **Vision Fuels** of Urbandale, would burn natural gas, a less-polluting but more costly fuel used by most Iowa ethanol facilities. Only a few of Iowa's 26 ethanol plants burn coal, according to the **Iowa Department of Natural Resources**. However, one firm eyeing the Des Moines project and others in Iowa is looking to save money by burning coal.

## NUCLEAR

***Toshiba Completes Acquisition of Westinghouse Electric***

**Toshiba** has completed the purchase of **Westinghouse Electric Co**., acquiring a 77 percent stake in the U.S. producer of nuclear power plant equipment for $4.16 billion. The **Shaw Group Inc**. bought a 20 percent stake for $1.08 billion and **Ishikawajima-Harima Heavy Industries Co.** purchased a three percent stake for $162 million. The Westinghouse deal means Toshiba will gain a 28 percent share of the global market, according to the company.

***Atmostryexport to Build 2 x 1,000 MW Nuclear Power Plant in Bulgaria***

Bulgaria has selected the Russian firm **Atmostryexport** to build a multi-billion dollar nuclear power plant at Belene on the Danube. The two 1,000 MW light-water reactors would join existing installations of the same capacity at Kosloduy. The Kosloduy plant is preparing to shut down two Soviet-era 440 MW nuclear reactors before Bulgaria joins the European Union on January 1, 2007.

## RENEWABLES

### *Vestas to Supply Wind Turbines for Chinese Wind Power Companies*

**Vestas** has orders for 50 units of the V80-2.0 MW wind turbine and 53 units of the V52-850 kW wind turbine for two wind power projects in China. The orders have been placed by **Longyuan Pingtan Wind Power Co., Ltd.** and **Huaneng Shantou Wind Power Co. Ltd**. respectively. Delivery of the turbines will start in Q4 2006 and commissioning of the wind power plants is planned to take place during 2007. The projects are located on the Islands Pingtan and Nanao, located in the southeastern province of Fujian.

### *Xcel Looks to Hydroelectric and Wind Power*

In an application to the **Minnesota Public Utilities Commission**, **Xcel** proposes a combined hydroelectric/wind-power package starting in 2015 to fill a projected baseload shortfall of 375 MW. Xcel would buy 375 MW of power from **Manitoba Hydro** beginning in 2015 and buy or generate 380 MW of wind power by 2015.

### *Indiana Michigan Power Discussing Wind Farms*

**Indiana Michigan Power** (I&M) has invited 250 residents of Jay, Randolph and Wayne counties to meetings next week to discuss the possibility of developing a wind farm. The electric utility is seeking people willing to lease their land to I&M for the installation of two or three 200-foot meteorological towers to collect wind data. If the data show that a wind farm is feasible, either I&M or a developer would plan to lease land for the installation of wind turbines. “A typical 100 MW wind farm would cover an area up to 12 square miles,” Mike Brian, I&M spokesman, said. “It would be spread out over a wide area.” While more than 10,000 MW of wind energy capacity have been installed in the United States, Indiana currently has none, though **Orion Energy** is placing up to 135 wind turbines capable of producing 200 MW of electricity in Benton County.

### *GE Turbines for Su Jia He Kou Hydroelectric Plant in China*

**GE Energy** technology has been selected for a new 300 MW hydropower plant to be located on the Bing Lang Jiang River in Baoshan City, Yunnan Province, China. The Su Jia He Kou hydropower plant will feature three high-head, vertical Francis hydro turbine-generators, each with a maximum 105 MW output. Owner of the new power plant is **Yunnan Baoshan Bing Lang Jiang Hydro Power Development Co. Ltd**. The first unit is expected to enter commercial operation by June of 2009.

## HOT TOPICS

### *Haldor Topsoe Catalyst Efficiency Revisted*

During our SCR Hot Topic Hour (October 12) we reviewed the performance of the **Haldor Topsoe** catalyst. Nate White has supplied this additional information:

Haldor Topsoe provides a composite/hybrid (corrugated) SCR catalyst with a Tri-modal pore distribution that increases both catalyst activity and poison resistance. Topsoe has supplied catalyst to twelve coal-fired boilers burning high sulfur, high arsenic coals without limestone addition, one exceeding 28,000 hours of service with only two layers of catalyst. Haldor Topsoe reported they have provided catalyst for several installations that consistently run at less than 0.03 lb/MMBtu $NO_x$ for both bituminous and sub-bituminous coals. Topsoe has over 100,000 hours of operating experience on PRB coal. In fact, three Topsoe supplied SCRs achieved the highest $NO_x$ efficiency for all U.S. coal-fired high dust SCRs, averaging over 95 percent $NO_x$ reduction over the 2005 Ozone season. The Tri-modal pore distribution is also advantageous in reducing $SO_2$-oxidation. Topsoe has two installations with three catalyst layers that have operated over 100,000 hours with an overall SCR $SO_2$-oxidation of less than 0.1 percent. They now report they have supplied additional catalyst layers to eight U.S. boilers without adding any measurable increase in $SO_2$ oxidation, several designed for less than 0.05 percent $SO_2$ oxidation per layer.

### *$PM_{2.5}$ Hot Topic Hour Reveals that Firm Guarantees are being made based on Questionable Monitoring Methods*

http://www.mcilvainecompany.com/utility/subscriber/Hot_Topic_Hour_Recordings.htm

This link is for registered subscribers and is free of charge. Even though your company may be a subscriber but you are not a registered additional user, you can still access this recording at $95 for a period of six months. But the cost of becoming an additional user is not much more, so this would be a better option. In any case the link for those interested in individual tape access is
http://www.mcilvainecompany.com/FGDnetoppbroch/hottopichourrecordings.htm

This was a very valuable session because we had insights from the individual at EPA most responsible for the specific development of $PM_{2.5}$ monitors, the executive director of the association of companies which has to make guarantees based on the reliability of these instruments, utilities who were knowledgeable enough to spot some of the potential weaknesses in the designs, consultants who are focused on the $PM_{2.5}$ issues, and suppliers of continuous emissions monitors whose results must be correlated with the stack methods.

The undeniable conclusion from this two hour session is that there is a major problem with the time table. Firm guarantees are being made without a reliable method of proving those guarantees. There are many millions of dollars in guarantee risks and hundreds of

millions of dollars in risks involving permission to operate contingent on meeting specific limits as low as 0.018 lbs/MMBtu of particulate 2.5 microns and smaller including condensibles.

Method 202 is the method which will be used to validate the guarantees, but EPA is working on an improved method which will eliminate some of the artifacts. It also has a new conditional method using dilution sampling which appears promising, but this new method is not advanced to the point of replacing Method 202.

Here are some highlights from the presentations:

More than 40 people including utilities, government, A/Es, and suppliers participated in a two- hour discussion of the perplexing problem of measuring and controlling fine particulate. The discussion started with a brief tour of the Particulate Decision tree. An extensive analysis in the Decision Tree shows that discrete fine particle emissions from U.S. power plants could be as low as 100,000 tons per year or as high as one million tons per year. When you add in the condensibles you add another 200,000 to 500,000 tons/yr.

There were six semi-formal presentations and two inputs from expert panelists. The semi-formal presentations can be viewed without the audio directly in the Decision Tree through the links provided below. The full recording with all the presentations both video and audio is available through the Utility Environmental Tracking System,

http://www.mcilvainecompany.com/utility/subscriber/Hot_Topic_Hour_Recordings.htm

or the Power Plant Air Quality Decisions.

http://www.mcilvainecompany.com/ppks/subscriber/Hot_Topic_Hour_Recordings.htm

**Ron Myers, EPA**

Start ► More Particulate Removal Necessary? ► Regulations ► U.S. ► National ► PM2.5

Ron provided the very latest data on performance of the dilution sampling system which has been designated as conditional test method CTM 039. This system has been tested on seven sources including utility coal-fired boilers, oil-fired boilers and cement plants. Data correlates well with an improved Method 202 but not will the original method which is referenced in the permits. The designated method has a bias which converts some of the $SO_2$ and considers it additional particulate.

**Dave Foerter, ICAC**

Start ► More Particulate Removal Necessary? ► Regulations ► U.S. ► National ► PM2.5

Dave reviewed the history of ambient air particulate legislation and pointed out that this year the 24-hour standard has been reduced from 65 ug/m$^3$ to 15 ug/m$^3$. He also

emphasized that the air pollution control companies are being required to make $PM_{2.5}$ guarantees and are in a difficult situation. Since Method 202 results in reporting erroneously high particulate weights and since it is the designated method, it is a big problem for the suppliers.

**Buzz Reynolds, Siemens-Wheelabrator**

Start ▶ Particulate Removal ▶ Physical ▶ Design of Equipment ▶ Precipitators ▶ Wet ▶ Sources ▶ Wheelabrator/Siemens ▶ Products

This potentially interesting presentation was postponed due to some access problem. Due to the security software at some of the big companies it takes a special effort to use Webex.

**Bob Crynack, Indigo Agglomerator**

Start ▶ Particulate Removal ▶ Physical ▶ Design of Equipment ▶ Hybrid ▶ Electrical Enhancement of Precipitator ▶ Sources ▶ Indigo Technologies ▶ Products

Bob presented data to show that the Indigo Agglomerator is effective on fine particles. In a subsequent discussion, the question was raised as to the effectiveness on nanoparticles. One hypothesis is that particles less than 100 nanometers will act more like a gas and pass through a fabric filter, but if these particles are charged they may be captured in the fabric filter.

> *Editor note: See discussion of nanoparticles below. But is it possible that precipitators do better on nanoparticles than fabric filters? The problem is that we cannot even count the number of nanoparticles, so proving this hypothesis is not going to be easy.*

**Craig Clapsaddle, MSI**

Start ▶ Particulate Removal ▶ Physical ▶ Component Specification ▶ Common Components ▶ Optimization & Instrumentation ▶ Mass Monitoring ▶ Sources ▶ MSI ▶ Products

Craig provided details on the ability of the BetaGuard particulate mass monitor to accurately measure mass emissions following a wet FGD system. Many States are incorporating mass monitoring requirements downstream of wet FGD in their permits for new plants. Craig pointed out that in some cases there is as much as a 90 percent reduction in discrete fine particulate in the scrubber. Several utilities that were having problems with meeting opacity limits after the precipitator were able to demonstrate compliance by installing the BetaGuard and proving the further reductions in the FGD.

*Editor note: Since discrete particulate is a surrogate for heavy metals and there is likely to be significant reduction in the wet scrubber if it follows an old precipitator, this wet stack measurement is particularly valuable.*

**Otakar Jonas, Jonas Inc.**



Tests were run at a DuPont incinerator some years ago and showed the inaccuracies of some of the CEMS in continuously monitoring mass. The acoustic emission monitor has some advantages.

**Panelists**

John McKenna of ETS was one of the panelists. He pointed out that $PM_{2.5}$ is defined as all particles of this diameter or smaller. So, he asks, what about nanoparticles? John operates a fabric verification program for EPA. When challenging today's fabrics with 100 nanometer particles, there is little difference between fabrics.

But if John were to use a particle counter rather than a weight measurement, he would be able to discern performance differences. As Bob Crynack pointed out in his presentation, there are many thousands of particles less than 0.1 micron in each cubic centimeter of flue gas. So measurement with a condensation nuclei particle counter could show differences of thousands or hundreds of thousands of particles in each cubic foot of flue gas passed through one fabric as compared to another.

Bill Ellison was a panelist and addressed the questions posed at the beginning of the session as follows:

Responding to several of McIlvaine's nine recently posted sub-topic areas:

(1) <u>What percentage of $PM_{2.5}$ is condensables</u>? A major proportion, especially in high-sulfur service. $H_2SO_4$ is the "tail" wagging the "dog" in the current era of low $PM_{2.5}$ emission limits out of "sync" with sulfur emission limits.

(2) <u>Should there be a separate $SO_3$ measurement</u>? No. That portion of the $H_2SO_4$ that would be expected to condense in the real-life flue gas treatment train prior to stack exit should (via the sample/test train) be summed-in with the $PM_{2.5}$ solids catch. Accordingly, the "back end" of the sample train should be operated at the same temperature as that at the stack-inlet, i.e.:

(a) A nominal 300ºF for an unscrubbed unit (or, logically, there is no back end catch available to be caught).

(b) The flue gas wet bulb temperature, e.g. 122ºF for bituminous coal-firing, for wet scrubbed units.

(c) The above temperature for wet scrubbers plus the unit's actual amount of temperature approach to wet bulb for dry or semi-dry scrubbers (an appreciable "back end" catch for spray dryers but not for CFB scrubbers.)

*Editor's comments: Bill is recommending an approach which measures the real time particulate. But the $SO_3$ will convert to $H_2SO_4$ within a short distance from the stack. (The difference is that all the $SO_3$ is converted prior to the stack exit when wet scrubbers are used. However, some of the $SO_3$ is captured.) Therefore EPA is considering this primary particulate as part of PM 2.5. By contrast $SO_2$ forms compounds much farther from the stack and is therefore considered a source of secondary particulate. Bill's approach will make the dry scrubber people happy. But the wet scrubber people will justifiably point out that within a short distance from the stack the $H_2SO_4$ will be less rather than more. Therefore why discourage more $SO_3$ removal?*

(3) <u>If I already have a precipitator, how much further reduction will I achieve when I install my wet FGD?</u> None. Absent a wet ESP mist eliminator and its mitigating effect, $PM_{2.5}$ will <u>increase</u> due to each of:

(a) $H_2SO_4(\ell)$ formation in the wet scrubber, (i.e. that portion of raw-gas $SO_3/H_2SO_4(v)$ not removed in the scrubber, e.g. 50%).

(b) The solids component, suspended and dissolved, of the scrubber carryover, less that amount of particulate solids removed (inefficiently) in the wet scrubber, the latter being minimal in the case of an existing upstream precipitator of modern sizing with high solid particulate removal efficiency.

*Editor note. However, many of the installations involve new FGD on plants with old precipitators. In general the scrubber can bring emissions down to 0.05 lbs/MMBtu. So if the inlet is 0.15 lbs/MMBtu then the scrubber can achieve a 66% reduction. But if the precipitator outlet emission is only 0.02 lbs/MMBtu the scrubber will not likely have any additional reduction. There is one exception. When there is a precipitator excursion, the scrubber particulate capture will be significant.*

***Hot Topic Discussion of Spray Dryer vs. CFB FGD November 9***

Join us at 9:00 a.m., November 9th for the Hot Topic Hour discussion of dry FGD. This 90 minute web/audio discussion will address all the important selection factors including:

When is dry FGD a better choice than wet?
How do spray dryer, CFB, and CDS systems compare in efficiency and reliability?
Can spray dryer systems achieve more than 90 percent efficiency with high acid dewpoints?
How do dual fluid nozzles and rotary atomizers compare in performance?
How much downtime is required for rotary atomizers?
Will there be lime available in the quantity needed and at an affordable price?
How do you dispose of the flyash gypsum mix?
What removal efficiency will you achieve on $SO_3$?
Can ACI be co-injected for mercury removal?
What bag and media selections are best for this application?

For more information on this and other hot topic hours discussions click on

**http://www.mcilvainecompany.com/FGDnetoppbroch/Default1.htm**

## SCHEDULE FOR FUTURE HOT TOPIC HOURS

| | |
|---|---|
| **November 16** | **Mercury CEMS: Commercial availability** |
| ***November 27*** | ***Power-Gen – all day decision making session in Orlando*** |
| **December 7** | **Air Pollution Investment Opportunities** |
| ***December 11-13*** | ***DOE Mercury, Pittsburgh - available for discussions*** |
| **January 11** | **Corrosion materials options** |
| **January 18** | **Comparison of limestone wet scrubber designs** |
| ***January 21-24*** | ***EUEC Tucson - available for discussions*** |
| **February 1** | **Chinese FGD/SCR program and impact on the world** |
| **February 15** | **Mercury control cost and performance** |
| **February 22** | **$SO_3$ issues and answers** |

## ACCESSING ALL THE PROJECTS AND INFORMATION ONLINE

This Utility E-Alert is part of the **Utility Upgrade Environmental Tracking System**. The system allows you to instantly retrieve project details, profiles of each coal-fired plant worldwide, the right contacts at the OEM and A/E firms and summaries of all the scheduled FGD and SCR projects.

You need a user name and password to access this system. If you have forgotten these or are not sure whether you are eligible, email editor@mcilvainecompany.com.

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# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 12/19/00 | 0.0004 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/6/03 | 0.0006 | 17 |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 12/8/03 | 0.0006 | 5 |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 12/8/03 | 0.0007 | |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 12/4/02 | 0.0008 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 12/17/98 | 0.001 | |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 10/5/01 | 0.0013 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 9/4/02 | 0.002 | 201A |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/4/03 | 0.002 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/4/03 | 0.002 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 12/12/03 | 0.002 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 11/8/02 | 0.0026 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 12/10/02 | 0.0026 | 5 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 10/28/03 | 0.0028 | 5 |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 3/13/91 | 0.003 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 4/15/92 | 0.003 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 3/29/96 | 0.003 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 9/4/02 | 0.003 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/4/03 | 0.003 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/4/03 | 0.003 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 4/3/96 | 0.003 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/18/00 | 0.003 | 17 |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 11/16/99 | 0.003 | |
| 0810010 | FLORIDA POWER & LIGHT (PMT) | MANATEE POWER PLANT | 2 | Fossil Fuel Steam Generator, Unit 2-Phase II Acid Rain Unit | 2/25/03 | 0.003 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 12/10/02 | 0.003 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 2/27/03 | 0.003 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 6/11/03 | 0.003 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 9/18/03 | 0.003 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 9/25/03 | 0.003 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 10/16/03 | 0.003 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 10/27/03 | 0.003 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 10/27/03 | 0.003 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 10/27/03 | 0.003 | 5 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 10/28/03 | 0.003 | 201A |
| 0310001 | JACKSONVILLE ELECTRIC AUTHORITY | ST.JOHNS RIVER POWER PARK | 4 | NO.2 STEAM GENERATOR A | 10/11/99 | 0.003 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 6/9/93 | 0.003 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 5/16/00 | 0.003 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 4/30/02 | 0.003 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 10/11/99 | 0.0033 | 5B |
| 0010006 | CITY OF GAINESVILLE, GRU | DEERHAVEN GEN. STA. | 5 | Fossil Fuel Fired Steam Generator #2 (Phase I & II AR Unit) | 6/23/03 | 0.00338 | 17 |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 6 | McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit) | 6/15/95 | 0.00349 | |
| 0090008 | ORLANDO UTLITIES COMMISSION | INDIAN RIVER PLANT - OUC | 3 | FOSSIL FUEL STEAM GENERATOR UNIT #3 | 6/15/93 | 0.0036 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 2/27/03 | 0.0037 | 5 |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 4/5/95 | 0.004 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 3/25/99 | 0.004 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/6/03 | 0.004 | 201A |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/6/03 | 0.004 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 6/30/02 | 0.004 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 9/24/03 | 0.004 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 10/16/03 | 0.004 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 12/12/03 | 0.004 | 17 |
| 1270009 | FLORIDA POWER & LIGHT (PSN) | SANFORD POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 4 (Phase II Acid Rain Unit) | 6/25/96 | 0.004 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 2 | PULVERIZED COAL FIRED UNIT NO. 2 (460 MW GROSS) | 4/24/01 | 0.004 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 9/24/02 | 0.00408 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 12/19/00 | 0.0043 | 5B |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 2/28/03 | 0.0043 | 5 |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 9/21/95 | 0.0043 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 2/5/03 | 0.0045 | 17 |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 11/16/98 | 0.0045 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 9/24/02 | 0.0046 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/19/01 | 0.0047 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 10/12/98 | 0.0047 | 5B |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 1/29/02 | 0.0048 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 12/9/02 | 0.0049 | 5 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/12/02 | 0.005 | 201A |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/12/02 | 0.005 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/13/02 | 0.005 | 201A |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/13/02 | 0.005 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/14/02 | 0.005 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/14/02 | 0.005 | 201A |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/14/02 | 0.005 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 3/14/00 | 0.005 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 12/19/02 | 0.005 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 1/30/03 | 0.005 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 12/10/01 | 0.005 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 12/10/01 | 0.005 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 12/10/02 | 0.005 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 6/11/03 | 0.005 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 9/17/03 | 0.005 | 201A |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|---|
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | | 9/24/03 | 0.005 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | | 9/25/03 | 0.005 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | | 10/7/03 | 0.005 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | | 10/28/03 | 0.005 | 17 |
| 0310001 | JACKSONVILLE ELECTRIC AUTHORITY | ST.JOHNS RIVER POWER PARK | 4 | NO.2 STEAM GENERATOR | A | 11/3/97 | 0.005 | 5B |
| 0310001 | JACKSONVILLE ELECTRIC AUTHORITY | ST.JOHNS RIVER POWER PARK | 1 | #1 STEAM GENERATOR UNIT | A | 11/4/97 | 0.005 | 5B |
| 0310001 | JACKSONVILLE ELECTRIC AUTHORITY | ST.JOHNS RIVER POWER PARK | 4 | NO.2 STEAM GENERATOR | A | 10/12/98 | 0.005 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | | 3/14/02 | 0.0051 | 17 |
| 1030011 | PROGRESS ENERGY FLORIDA, INC. | BARTOW PLANT | 2 | No.2 Unit, FFSG (Phase II Acid Rain Unit) | | 5/18/93 | 0.005235 | |
| 0530021 | FLORIDA CRUSHED STONE CO., INC. | BROOKSVILLE CEMENT AND POWER PLANTS | 18 | BPP: POWER PLANT | | 9/12/01 | 0.0053 | 5 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | | 6/11/03 | 0.0053 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | | 2/4/03 | 0.0054 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | | 3/12/02 | 0.0055 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | | 2/4/99 | 0.0055 | 5B |
| 0530021 | FLORIDA CRUSHED STONE CO., INC. | BROOKSVILLE CEMENT AND POWER PLANTS | 18 | BPP: POWER PLANT | | 4/25/00 | 0.005565 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | | 3/21/01 | 0.0056 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | | 10/14/99 | 0.0057 | 5B |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | | 3/10/93 | 0.006 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | | 3/19/97 | 0.006 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | | 3/19/97 | 0.006 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | | 3/12/02 | 0.006 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | | 3/6/03 | 0.006 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | | 1/29/03 | 0.006 | 17 |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 2 | BOILER NUMBER 2 - 2,246.2 MMBTU/HOUR (PHASE II ACID RAII | | 8/6/93 | 0.006 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | | 6/30/02 | 0.006 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | | 9/19/03 | 0.006 | 201A |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | | 10/7/03 | 0.006 | 17 |
| 0310001 | JACKSONVILLE ELECTRIC AUTHORITY | ST.JOHNS RIVER POWER PARK | 1 | #1 STEAM GENERATOR UNIT | A | 10/14/99 | 0.006 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | | 6/24/92 | 0.006 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | | 1/31/95 | 0.00639 | |
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 6 | McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit) | | 6/23/93 | 0.0065 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | | 2/1/95 | 0.0065 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | | 3/13/02 | 0.0065 | 17 |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | | 4/23/97 | 0.0065 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | | 1/30/02 | 0.0067 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 1 | Cogeneration Boiler A - 715 MMBtu/hr spreader stoker boiler | | 2/13/04 | 0.0068 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | | 4/3/01 | 0.0069 | 17 |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | | 3/30/00 | 0.007 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | | 3/21/01 | 0.007 | 201A |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/13/02 | 0.007 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/13/02 | 0.007 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 3/7/00 | 0.007 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 9/17/03 | 0.007 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 9/18/03 | 0.007 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 9/19/03 | 0.007 | 17 |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 2 | Steam Electric Generator No. 2 | 7/26/01 | 0.007 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 2 | PULVERIZED COAL FIRED UNIT NO. 2 (460 MW GROSS) | 5/23/00 | 0.007 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 3/2/00 | 0.0071 | 5B |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 4/3/95 | 0.00713 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 5/21/02 | 0.0073 | 17 |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 4/3/01 | 0.0076 | 17 |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 2 | PULVERIZED COAL FIRED UNIT NO. 2 (460 MW GROSS) | 5/20/03 | 0.0076 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 10/13/98 | 0.0077 | 5B |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 3 | Cogeneration Boiler C - 715 MMBtu/hr spreader stoker boiler | 2/13/04 | 0.0078 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 2 | Cogeneration Boiler B - 715 MMBtu/hr spreader stoker boiler | 1/23/03 | 0.0079 | |
| 0530021 | FLORIDA CRUSHED STONE CO., INC. | BROOKSVILLE CEMENT AND POWER PLANTS | 18 | BPP: POWER PLANT | 5/25/01 | 0.00797 | 5 |
| 1030011 | PROGRESS ENERGY FLORIDA, INC. | BARTOW PLANT | 1 | No.1 Unit, FFSG (Phase II Acid Rain Unit) | 9/8/97 | 0.008 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 5/7/98 | 0.008 | 17 |
| 0810010 | FLORIDA POWER & LIGHT (PMT) | MANATEE POWER PLANT | 1 | Fossil Fuel Steam Generator, Unit 1-Phase II Acid Rain Unit | 11/4/03 | 0.008 | 17 |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 1 | Cogeneration Boiler A - 715 MMBtu/hr spreader stoker boiler | 2/13/02 | 0.008 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 7/14/93 | 0.008 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/15/93 | 0.008 | |
| 0310001 | JACKSONVILLE ELECTRIC AUTHORITY | ST.JOHNS RIVER POWER PARK | 1 | #1 STEAM GENERATOR UNIT A | 10/13/98 | 0.008 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 17 | SJRPP #2 Steam Generator (Phase I & II Acid Rain Unit) | 3/1/00 | 0.0081 | 5B |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 3 | Cogeneration Boiler C - 715 MMBtu/hr spreader stoker boiler | 1/21/03 | 0.0081 | |
| 0530032 | CENTRAL POWER & LIME, INC. | CENTRAL POWER & LIME, INC. | 14 | POWER PLANT | 2/12/97 | 0.00814 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 3 | Cogeneration Boiler C - 715 MMBtu/hr spreader stoker boiler | 7/21/00 | 0.0083 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 1 | Cogeneration Boiler A - 715 MMBtu/hr spreader stoker boiler | 5/9/96 | 0.0084 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 9/7/95 | 0.00845 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 2/28/03 | 0.0087 | 17 |
| 0530032 | CENTRAL POWER & LIME, INC. | CENTRAL POWER & LIME, INC. | 14 | POWER PLANT | 5/24/99 | 0.0088 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 1 | Cogeneration Boiler A - 715 MMBtu/hr spreader stoker boiler | 1/22/03 | 0.0089 | |
| 1030011 | PROGRESS ENERGY FLORIDA, INC. | BARTOW PLANT | 1 | No.1 Unit, FFSG (Phase II Acid Rain Unit) | 9/8/97 | 0.009 | |
| 1030011 | PROGRESS ENERGY FLORIDA, INC. | BARTOW PLANT | 1 | No.1 Unit, FFSG (Phase II Acid Rain Unit) | 9/9/97 | 0.009 | 17 |
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 5 | McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit) | 7/2/92 | 0.009 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/20/01 | 0.009 | 201A |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/17/91 | 0.009 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/25/95 | 0.009 | |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 4/22/97 | 0.009 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 2/17/99 | 0.009 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 6/17/99 | 0.009 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 3/7/00 | 0.009 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 3/14/00 | 0.009 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 5/2/01 | 0.009 | |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 2 | BOILER NUMBER 2 - 2,246.2 MMBTU/HOUR (PHASE II ACID RAII | 8/5/93 | 0.009 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 8/14/92 | 0.009 | |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 2 | Steam Electric Generator No. 2 | 5/8/00 | 0.009 | |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 2 | Steam Electric Generator No. 2 | 7/28/01 | 0.009 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 6/30/91 | 0.009 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 6/29/94 | 0.009 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 5/1/01 | 0.009 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 11/8/02 | 0.0091 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 3/20/01 | 0.0093 | |
| 0530021 | FLORIDA CRUSHED STONE CO., INC. | BROOKSVILLE CEMENT AND POWER PLANTS | 18 | BPP: POWER PLANT | 9/4/02 | 0.00977 | 5 |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 2 | Cogeneration Boiler B - 715 MMBtu/hr spreader stoker boiler | 2/13/04 | 0.0098 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 3/14/02 | 0.01 | |
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 6 | McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit) | 7/7/00 | 0.01 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 4/23/97 | 0.01 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 6/18/97 | 0.01 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 6/16/99 | 0.01 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 3/6/01 | 0.01 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 2/6/02 | 0.01 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 2/7/02 | 0.01 | 17 |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 9/21/98 | 0.01 | |
| 0090008 | ORLANDO UTLITIES COMMISSION | INDIAN RIVER PLANT - OUC | 1 | FOSSIL FUEL STEAM GENERATOR, UNIT #1 | 6/29/94 | 0.01 | |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 5/22/03 | 0.01 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 12/11/01 | 0.01 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 12/11/01 | 0.01 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 3 | Cogeneration Boiler C - 715 MMBtu/hr spreader stoker boiler | 1/3/01 | 0.01 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 2 | Cogeneration Boiler B - 715 MMBtu/hr spreader stoker boiler | 2/14/02 | 0.01 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 8/19/99 | 0.01 | 17 |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 2 | PULVERIZED COAL FIRED UNIT NO. 2 (460 MW GROSS) | 8/9/96 | 0.01 | |
| 0850102 | INDIANTOWN COGENERATION, L.P. | INDIANTOWN COGENERATION PLANT | 1 | Pulverized Coal Main Boiler | 10/2/00 | 0.0102 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 1 | Cogeneration Boiler A - 715 MMBtu/hr spreader stoker boiler | 8/18/00 | 0.0103 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 4 | Fossil Fuel Steam Generator-4 (Phase I & II Acid Rain Unit) | 8/12/03 | 0.0104 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 3/26/03 | 0.01048 | |
| 1030011 | PROGRESS ENERGY FLORIDA, INC. | BARTOW PLANT | 3 | No.3 Unit, FFSG (Phase II Acid Rain Unit) | 7/17/00 | 0.0105 | 17 |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0530021 | FLORIDA CRUSHED STONE CO., INC. | BROOKSVILLE CEMENT AND POWER PLANTS | 18 | BPP: POWER PLANT | 9/4/02 | 0.0106 | 5 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 26 | NGS - Circulating Fluidized Bed Boiler No. 2 | 12/18/02 | 0.0107 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 27 | NGS - Circulating Fluidized Bed Boiler No. 1 | 12/19/02 | 0.0107 | 17 |
| 0530021 | FLORIDA CRUSHED STONE CO., INC. | BROOKSVILLE CEMENT AND POWER PLANTS | 18 | BPP: POWER PLANT | 9/19/03 | 0.011 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/7/00 | 0.011 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/5/03 | 0.011 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/5/03 | 0.011 | 201A |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/5/03 | 0.011 | 201A |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 5/26/93 | 0.011 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 3/11/98 | 0.011 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/19/00 | 0.011 | 17 |
| 0770009 | DG ENERGY SOLUTIONS, LLC | DG TELOGIA POWER, LLC | 1 | Carbonaceous Boiler | 10/7/98 | 0.011 | 5 |
| 0770009 | DG ENERGY SOLUTIONS, LLC | DG TELOGIA POWER, LLC | 1 | Carbonaceous Boiler | 11/2/01 | 0.011 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 3 | Cogeneration Boiler C - 715 MMBtu/hr spreader stoker boiler | 2/12/02 | 0.011 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 6/13/90 | 0.011 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 6/13/90 | 0.011 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 8/12/92 | 0.011 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/16/93 | 0.011 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 8/18/99 | 0.011 | 17 |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 8/2/00 | 0.011 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 2 | PULVERIZED COAL FIRED UNIT NO. 2 (460 MW GROSS) | 8/18/97 | 0.011 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 8/6/03 | 0.0112 | |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 1 | Steam Electric Generator No. 1 | 7/16/02 | 0.01134 | |
| 0010006 | CITY OF GAINESVILLE, GRU | DEERHAVEN GEN. STA. | 5 | Fossil Fuel Fired Steam Generator #2 (Phase I & II AR Unit) | 6/5/00 | 0.0115 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/26/95 | 0.012 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 6/5/96 | 0.012 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 3/17/98 | 0.012 | 17 |
| 0990331 | PALM BEACH POWER CORP. | OSCEOLA COGENERATION PLANT (INACTIVE | 1 | 760 MMBTU/HR BIOMASS/OIL/COAL FIRED BOILER | 12/14/96 | 0.012 | |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 1 | Steam Electric Generator No. 1 | 7/25/01 | 0.012 | |
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 6 | McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit) | 7/24/97 | 0.0121 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/3/97 | 0.0125 | 5B |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 9/4/02 | 0.0125 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 8/28/02 | 0.0126 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 4 | Fossil Fuel Steam Generator-4 (Phase I & II Acid Rain Unit) | 8/16/01 | 0.0127 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 4 | Fossil Fuel Steam Generator-4 (Phase I & II Acid Rain Unit) | 9/3/02 | 0.0127 | |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 4 | Unit No. 4 Steam Generator (Phase II Acid Rain Unit) | 4/22/98 | 0.013 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/5/97 | 0.013 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/7/00 | 0.013 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/7/00 | 0.013 | |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 6/6/90 | 0.013 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 5/6/98 | 0.013 | 17 |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 4/26/96 | 0.013 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 4/23/97 | 0.013 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 9/18/97 | 0.013 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 8/16/01 | 0.013 | |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 7/26/94 | 0.013 | |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 2 | BOILER NUMBER 2 - 2,246.2 MMBTU/HOUR (PHASE II ACID RAII | 5/19/03 | 0.013 | 17 |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 2 | Cogeneration Boiler B - 715 MMBtu/hr spreader stoker boiler | 1/16/01 | 0.013 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 6/12/90 | 0.013 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 7/13/93 | 0.013 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/13/95 | 0.013 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/16/97 | 0.013 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/4/97 | 0.0133 | 5B |
| 0530032 | CENTRAL POWER & LIME, INC. | CENTRAL POWER & LIME, INC. | 14 | POWER PLANT | 2/27/96 | 0.0135 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 5/17/00 | 0.0136 | |
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 6 | McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit) | 6/23/93 | 0.0138 | |
| 0530032 | CENTRAL POWER & LIME, INC. | CENTRAL POWER & LIME, INC. | 14 | POWER PLANT | 6/16/98 | 0.0139 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/16/99 | 0.014 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/7/00 | 0.014 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/16/91 | 0.014 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 3/7/01 | 0.014 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 10/11/96 | 0.014 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 7/11/95 | 0.014 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/15/97 | 0.014 | 17 |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 1 | Steam Electric Generator No. 1 | 7/27/01 | 0.014 | |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 1 | Steam Electric Generator No. 1 | 7/18/02 | 0.01422 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/8/96 | 0.0143 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/19/01 | 0.0143 | 17 |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 3 | Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit) | 9/23/99 | 0.0144 | |
| 1050004 | LAKELAND ELECTRIC | C.D. MCINTOSH, JR. POWER PLANT | 6 | McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit) | 9/11/97 | 0.01449 | |
| 1030011 | PROGRESS ENERGY FLORIDA, INC. | BARTOW PLANT | 1 | No.1 Unit, FFSG (Phase II Acid Rain Unit) | 3/17/93 | 0.0145 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 8/7/03 | 0.0145 | |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 2 | Cogeneration Boiler B - 715 MMBtu/hr spreader stoker boiler | 11/27/02 | 0.0146 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/12/98 | 0.0149 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/18/99 | 0.015 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/7/00 | 0.015 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 3/1/94 | 0.015 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 3/2/94 | 0.015 | |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 4/17/96 | 0.015 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 6 | Boiler # 6 (Phase I Acid Rain Unit) | 2/16/99 | 0.015 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 3/10/99 | 0.015 | 17 |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 8/4/93 | 0.015 | |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 2 | BOILER NUMBER 2 - 2,246.2 MMBTU/HOUR (PHASE II ACID RAII | 8/2/95 | 0.015 | 17 |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 5/21/03 | 0.015 | 17 |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 8/11/92 | 0.015 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 12/16/97 | 0.015 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 2 | PULVERIZED COAL FIRED UNIT NO. 2 (460 MW GROSS) | 5/19/99 | 0.015 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 12/11/96 | 0.0153 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/21/01 | 0.0156 | 17 |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 1 | Unit No. 1 Steam Generator (Phase II Acid Rain Unit) | 11/20/02 | 0.01579 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 2 | CIRCULATING FLUIDIZED BED BOILER B | 3/7/96 | 0.0158 | 5B |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 5/17/00 | 0.0159 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/14/98 | 0.016 | 5B |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 1 | CIRCULATING FLUIDIZED BED BOILER A | 3/17/99 | 0.016 | 5B |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 5 | Boiler #5 (Phase I & II Acid Rain Unit) | 4/19/91 | 0.016 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/29/92 | 0.016 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 5/27/93 | 0.016 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 7 | Boiler #7 (Phase I Acid Rain Unit) | 9/27/95 | 0.016 | 17 |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 5/1/01 | 0.016 | |
| 0170004 | PROGRESS ENERGY FLORIDA, INC. | CRYSTAL RIVER POWER PLANT | 2 | Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit) | 8/29/02 | 0.016 | |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 2 | BOILER NUMBER 2 - 2,246.2 MMBTU/HOUR (PHASE II ACID RAII | 8/1/95 | 0.016 | 17 |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 10/17/00 | 0.016 | |
| 0310045 | JEA | NORTHSIDE/SJRPP | 16 | SJRPP #1 Steam Generator (Phase I & II Acid Rain Unit) | 10/17/00 | 0.016 | 5B |
| 0990332 | NEW HOPE POWER PARTNERSHIP | OKEELANTA COGENERATION PLANT | 1 | Cogeneration Boiler A - 715 MMBtu/hr spreader stoker boiler | 1/9/01 | 0.016 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 1 | Boiler #1 (Phase I & II Acid Rain Unit) | 6/12/90 | 0.016 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 8/13/92 | 0.016 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/13/95 | 0.016 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 7/10/96 | 0.016 | 17 |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/7/96 | 0.0161 | 5B |
| 0570039 | TAMPA ELECTRIC COMPANY | BIG BEND STATION | 1 | Unit No. 1 Steam Generator (Phase II Acid Rain Unit) | 11/20/02 | 0.0164 | |
| 0010006 | CITY OF GAINESVILLE, GRU | DEERHAVEN GEN. STA. | 5 | Fossil Fuel Fired Steam Generator #2 (Phase I & II AR Unit) | 6/6/01 | 0.0164 | |
| 0010006 | CITY OF GAINESVILLE, GRU | DEERHAVEN GEN. STA. | 5 | Fossil Fuel Fired Steam Generator #2 (Phase I & II AR Unit) | 6/6/01 | 0.0164 | |
| 0330045 | GULF POWER COMPANY | CRIST ELECTRIC GENERATING PLANT | 4 | Boiler #4 (Phase I & II Acid Rain Unit) | 4/29/03 | 0.0166 | 17 |
| 1070025 | SEMINOLE ELECTRIC COOPERATIVE, INC | SEMINOLE POWER PLANT | 2 | Steam Electric Generator No. 2 | 7/23/02 | 0.01683 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/7/00 | 0.017 | |
| 0310337 | CEDAR BAY COGENERATION INC. | CEDAR BAY COGENERATION INC. | 3 | CIRCULATING FLUIDIZED BED BOILER C | 3/20/01 | 0.017 | 17 |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 7/27/94 | 0.017 | |

# PM/PM10 SOURCE TEST RESULTS, STATE OF FLORIDA

| FACILITY ID | OWNER/COMPANY NAME | SITE NAME | EU ID | EU DESCRIPTION | TEST DATE | RESULT (lb/MMBtu) | METHOD |
|---|---|---|---|---|---|---|---|
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 5/7/96 | 0.017 | 17 |
| 0050014 | GULF POWER COMPANY | LANSING SMITH PLANT | 1 | BOILER NUMBER 1 - 1,944.8 MMBTU/HOUR (PHASE II ACID RAII | 5/8/96 | 0.017 | 17 |
| 0990331 | PALM BEACH POWER CORP. | OSCEOLA COGENERATION PLANT (INACTIVE | 1 | 760 MMBTU/HR BIOMASS/OIL/COAL FIRED BOILER | 12/14/96 | 0.017 | |
| 0630014 | GULF POWER COMPANY | SCHOLZ ELECTRIC GENERATING PLANT | 2 | Boiler #2 (Phase I & II Acid Rain Unit) | 8/7/01 | 0.017 | |
| 0950137 | ORLANDO UTILITIES COMMISSION | STANTON ENERGY CENTER | 1 | FOSSIL FUEL STEAM GENERATION UNIT #1 | 5/18/99 | 0.017 | |

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MONITORING PROGRAM

# Compliance Particulate Emissions Testing

**Performed at**
**Georgia Power Company**
**Plant Scherer**
**Units One, Two, Three and Four**
**Juliette, Georgia**

**Submitted By:**

Spectrum Systems Inc.
3410 W. Nine Mile Road
Pensacola, Florida 32526

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III. Test Methods and Sampling Procedures

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E: Process Data

F: Calibration Data

G: Sample Train Schematic

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I: Nomenclature

# I. Introduction

Spectrum Systems, Inc. of Pensacola, Florida was contracted by the Georgia Power Company in Atlanta, Georgia for the purpose of performing particulate emissions compliance testing. The testing was performed on April 29, 1998, on Units One and Two, and May 1, 1998, on Units Three and Four at Plant Scherer in Juliette, Georgia. The purpose of testing these sources was to confirm that they are in compliance with the regulations set for by the USEPA and the Georgia Department of Natural Resources, Environmental Protection Division. USEPA Method 17 was utilized for quantifying particulate emissions.

Greg Rollins, Jimmy Garrett and Ron Cooley of Spectrum Systems, Inc. performed the particulate testing. Clark Mitchell of Georgia Power Company coordinated the testing. Spectrum Systems would like to thank Mr. Mitchell and the Plant Scherer personnel for their cooperation throughout the testing process.

# II. Summary of Results

Below are shown the results from testing performed on Units One and Two at Plant Scherer. Shown in tabular form is the Unit's Generation in Megawatts, the Emission Rate in pounds per million Btu's (#/MMBtu), and the Allowable Rate in pounds per million Btu's (#/MMBtu).

## *Georgia Power Company*

*Plant Scherer*
*Unit One*
*April 29, 1998*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 878 | .033 | 0.100 |
| Run 2 | 878 | .034 | 0.100 |
| Run 3 | 879 | .033 | 0.100 |
| Avg. | 878 | .033 | 0.100 |

## *Georgia Power Company*

*Plant Scherer*
*Unit Two*
*April 29, 1998*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 871 | .026 | 0.100 |
| Run 2 | 877 | .028 | 0.100 |
| Run 3 | 875 | .030 | 0.100 |
| Avg. | 874 | .028 | 0.100 |

Below are shown the results from testing performed on Units Three and Four at Plant Scherer. Shown in tabular form is the Unit's Generation in Megawatts, the Emission Rate in pounds per million Btu's (#/MMBtu), and the Allowable Rate in pounds per million Btu's (#/MMBtu).

## *Georgia Power Company*

***Plant Scherer***

***Unit Three***

***May 1, 1998***

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 898 | .011 | 0.100 |
| Run 2 | 905 | .009 | 0.100 |
| Run 3 | 904 | .009 | 0.100 |
| Avg. | 902 | .010 | 0.100 |

## *Georgia Power Company*

***Plant Scherer***

***Unit Four***

***May 1, 1998***

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 890 | .004 | 0.100 |
| Run 2 | 896 | .003 | 0.100 |
| Run 3 | 892 | .002 | 0.100 |
| Avg. | 893 | .003 | 0.100 |

# III. Test Methods and Sampling Procedures

## Particulate

The sampling train that was used for execution of the particulate testing was manufactured by APEX Instruments, in Apex, North Carolina . The train meets all specifications as outlined by the U.S. Environmental Protection Agency.

As specified in the various test methods, all necessary calibrations on the dry gas meter, sampling tip, pitot tubes, thermocouples, and aneroid barometer were performed. The results of the calibrations are included in the Appendix.

The number of sample points and the sampling location were determined according to EPA Method 1. The test location and nearest disturbances (upstream and downstream) from the test site can be found in detail on the preliminary sample traverse data sheet in the Appendix.

EPA Method 2 was used to determine the stack gas velocity and volumetric flow rate. An S- type pitot tube was used in conjunction with an inclined oil gauge manometer. After each test repetition, a leak check was performed on the pitot manometer assembly and indicated no leak for 15 seconds.

Dry molecular weight was determined according to EPA Method 3 during each repetition by orsat analysis of integrated gas samples. The results of these analyses were reported on the field data sheets and in the Appendix.

US EPA Method 17, Determination of Particulate Emissions from Stationary Sources, was used to determine particulate concentrations. The sampling train consisted of a calibrated stainless steel nozzle, stainless steel in-stack filter holder, glass fiber filter, stainless steel probe, four impingers, 50' umbilical cord, pump, dry gas meter, and orifice.

Before each test, filter holder with filter was secured to the end of the probe. In each of the first two impingers was placed 100 milliliters of water. The third impinger was left empty, and the fourth impinger was loaded with 200.0 grams of silica gel. Before each repetition, an optional leak check was performed to ensure all connections are secure.

The probe was inserted into the stack at the first sample traverse point. The stack gas parameters were recorded on the field data sheet, the pump turned on, and the sampling rate set at the isokinetic rate. At the end of the sampling period for the first point, the probe was moved to the next traverse point, and the sampling rate adjusted to maintain the isokinetic rate for the measured gas parameters at that point. This procedure was followed until all of the traverse points had been sampled. At each point, the following information was measured and recorded on the field data sheet: dry gas meter volume, stack gas velocity pressure differential, orifice meter pressure differential, stack gas temperature, sample train filtration temperature, filter outlet temperature, impinger train exit temperature, dry gas meter inlet and outlet temperature, and sample train system vacuum. After all of the points had been sampled, the pump was turned off and the probe was removed from the stack.

Immediately following each repetition, a leak check was performed on the sample train and indicated less than the allowable 0.02 CFM. The train was then disassembled. The filter holder assembly was first removed and recovered for later weighing. Next the nozzle was flushed with acetone and the catch stored. Next, the moisture catch from impingers one, two, and three were

measured with a graduated cylinder. The silica gel from the fourth impinger was removed and weighed. The impingers were then reloaded as previously described.

After the test was completed, the filter and catches were returned to the laboratory. The filter containers were desiccated for a minimum of 24 hours, then weighed to a constant weight. The contents of each aceton nozzle wash bottle were transferred to tared beakers. The containers were then rinsed with acetone to ensure that all of the particulate matter was recovered. Each wash was evaporated at ambient temperature and pressure in the SSI laboratory. The evaporation was closely supervised to prevent "bumping" and subsequent loss of sample. Each beaker, with residue, was desiccated and weighed to the nearest 0.1 milligram.

# IV. Statement of Authenticity

The sampling and analysis for this report was carried out under my direction and supervision. I have reviewed the testing details and results of this report and hereby certify that the data contained within is authentic and accurate to the best of my knowledge.

Date: 5/13/98

Signature: James Garrett
James Garrett
Testing Engineer

# Compliance Particulate Emissions Testing

**Performed at**
**Georgia Power Company**
**Plant Scherer**
**Units One, Two, Three and Four**
**Juliette, Georgia**

**Submitted By:**

**Spectrum Systems Inc.**
**3410 W. Nine Mile Road**
**Pensacola, Florida 32526**

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H: Test Calculations

I: Nomenclature

# I. Introduction

Spectrum Systems, Inc. of Pensacola, Florida was contracted by the Georgia Power Company in Atlanta, Georgia for the purpose of performing particulate emissions compliance testing. The testing was performed on June 14 & 15, 2000, on Units One and Two, and June 13, 2000, on Units Three and Four at Plant Scherer in Juliette, Georgia. The purpose of testing these sources was to confirm that they are in compliance with the regulations set for by the USEPA and the Georgia Department of Natural Resources, Environmental Protection Division. USEPA Method 5 was utilized for quantifying particulate emissions.

Wayne Smith and Keith Duck of Spectrum Systems, Inc. performed the particulate testing. Greg Rollins of Georgia Power Company coordinated the testing. Spectrum Systems would like to thank Mr. Rollins and the Plant Scherer personnel for their cooperation throughout the testing process.

# II. Summary of Results

Below are shown the results from testing performed on Units One and Two at Plant Scherer. Shown in tabular form is the Unit's Generation in Megawatts, the Emission Rate in pounds per million Btu's (#/MMBtu), and the Allowable Rate in pounds per million Btu's (#/MMBtu).

## *Georgia Power Company*

### *Plant Scherer*

*Unit One*

*June 14, 2000*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 857 | .035 | 0.100 |
| Run 2 | 854 | .036 | 0.100 |
| Run 3 | 848 | .036 | 0.100 |
| Avg. | 853 | .036 | 0.100 |

## *Georgia Power Company*

### *Plant Scherer*

*Unit Two*

*June 15, 2000*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 874 | .033 | 0.100 |
| Run 2 | 874 | .034 | 0.100 |
| Run 3 | 873 | .035 | 0.100 |
| Avg. | 874 | .034 | 0.100 |

Below are shown the results from testing performed on Units Three and Four at Plant Scherer. Shown in tabular form is the Unit's Generation in Megawatts, the Emission Rate in pounds per million Btu's (#/MMBtu), and the Allowable Rate in pounds per million Btu's (#/MMBtu).

## *Georgia Power Company*

### *Plant Scherer*

*Unit Three*

*June 13, 2000*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 878 | .010 | 0.100 |
| Run 2 | 878 | .011 | 0.100 |
| Run 3 | 878 | .011 | 0.100 |
| Avg. | 878 | .011 | 0.100 |

## *Georgia Power Company*

### *Plant Scherer*

*Unit Four*

*June 13, 2000*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 915 | .004 | 0.100 |
| Run 2 | 915 | .004 | 0.100 |
| Run 3 | 916 | .004 | 0.100 |
| Avg. | 915 | .004 | 0.100 |

# III. Test Methods and Sampling Procedures

## Particulate

The sampling train that was used for execution of the particulate testing was manufactured by APEX Instruments, in Apex, North Carolina . The train meets all specifications as outlined by the U.S. Environmental Protection Agency.

As specified in the various test methods, all necessary calibrations on the dry gas meter, sampling tip, pitot tubes, thermocouples, and aneroid barometer were performed. The results of the calibrations are included in the Appendix.

The number of sample points and the sampling location were determined according to EPA Method 1. The test location and nearest disturbances (upstream and downstream) from the test site can be found in detail on the preliminary sample traverse data sheet in the Appendix.

EPA Method 2 was used to determine the stack gas velocity and volumetric flow rate. An S-type pitot tube was used in conjunction with an inclined oil gauge manometer. After each test repetition, a leak check was performed on the pitot manometer assembly and indicated no leak for 15 seconds.

Dry molecular weight was determined according to EPA Method 3 during each repetition by orsat analysis of integrated gas samples. The results of these analyses were reported on the field data sheets and in the Appendix.

US EPA Method 5, Determination of Particulate Emissions from Stationary Sources, was used to determine particulate concentrations. The sampling train consisted of a calibrated stainless

steel nozzle, probe with heated stainless steel liner, glass fiber filter and filter holder in which the filter outlet temperature could be monitored, four impingers, 50' umbilical cord, pump, dry gas meter, and orifice.

Before each test, the probe and filter holder assemblies are secured in the filter box. In each of the first two impingers was placed 100 milliliters of water. The third impinger was left empty, and the fourth impinger was loaded with 200.0 grams of silica gel. Before each repetition, an optional leak check was performed to ensure all connections are secure.

After the probe and filter heaters warmed up to the specified operating temperature, the probe was inserted into the stack at the first sample traverse point. The stack gas parameters were recorded on the field data sheet, the pump turned on, and the sampling rate set at the isokinetic rate. At the end of the sampling period for the first point, the probe was moved to the next traverse point, and the sampling rate adjusted to maintain the isokinetic rate for the measured gas parameters at that point. This procedure was followed until all of the traverse points had been sampled. At each point, the following information was measured and recorded on the field data sheet: dry gas meter volume, stack gas velocity pressure differential, orifice meter pressure differential, stack gas temperature, sample train filtration temperature, filter outlet temperature, impinger train exit temperature, dry gas meter inlet and outlet temperature, and sample train system vacuum. After all of the points had been sampled, the pump was turned off and the probe was removed from the stack.

Immediately following each repetition, a leak check was performed on the sample train and indicated less than the allowable 0.02 CFM. The train was then disassembled. The filter holder assembly was first removed and recovered for later weighing. Next the nozzle was flushed with acetone and the catch stored. Next, the moisture catch from impingers one, two, and three were

measured with a graduated cylinder. The silica gel from the fourth impinger was removed and weighed. The impingers were then reloaded as previously described.

After the test was completed, the filter and catches were returned to the laboratory. The filter containers were desiccated for a minimum of 24 hours, then weighed to a constant weight. The contents of each aceton nozzle wash bottle were transferred to tared beakers. The containers were then rinsed with acetone to ensure that all of the particulate matter was recovered. Each wash was evaporated at ambient temperature and pressure in the SSI laboratory. The evaporation was closely supervised to prevent "bumping" and subsequent loss of sample. Each beaker, with residue, was desiccated and weighed to the nearest 0.1 milligram.

# IV. Statement of Authenticity

The sampling and analysis for this report was carried out under my direction and supervision. I have reviewed the testing details and results of this report and hereby certify that the data contained within is authentic and accurate to the best of my knowledge.

Date: 7-26-00

Signature: Wayne E Smith
Wayne Smith
Testing Engineer

# Compliance Particulate Emissions Testing

Performed at
Georgia Power Company
Plant Yates
Units Six and Seven
Whitesburg, Georgia

Submitted By:

Spectrum Systems Inc.
3410 W. Nine Mile Road
Pensacola, Florida 32526

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05/06/2003 12:59 CLEMENTS*SWEET,PC → 15108450983 NO.707 P003

# I. Introduction

Spectrum Systems, Inc. of Pensacola, Florida was contracted by the Georgia Power Company in Atlanta, Georgia for the purpose of performing particulate emissions compliance testing. The testing was performed on June 27, 2001, on Units Six and Seven at Plant Yates in Whitesburg, Georgia. The purpose of testing these sources was to confirm that they are in compliance with the regulations set for by the USEPA and the Georgia Department of Natural Resources, Environmental Protection Division. USEPA Method 17 was utilized for quantifying particulate emissions.

Jimmy Garrett, Wayne Smith and Jermey Hynes of Spectrum Systems, Inc. performed the particulate testing. Greg Rollins of Georgia Power Company coordinated the testing. Spectrum Systems would like to thank Mr. Rollins and the Plant Yates personnel for their cooperation throughout the testing process.



05/06/2003 12:59 CLEMENTS&SWEET.PC → 15108450983 NO.707 D004

# II. Summary of Results

Below are shown the results from testing performed on Units Six and Seven at Plant Yates. Shown in tabular form is the Unit's Generation in Megawatts, the Emission Rate in pounds per million Btu's (#/MMBtu), and the Allowable Rate in pounds per million Btu's (#/MMBtu).

## *Georgia Power Company*
### *Plant Yates*
*Units Six*
*June 27, 2001*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 368 | 0.008 | 0.240 |
| Run 2 | 365 | 0.006 | 0.240 |
| Run 3 | 367 | 0.010 | 0.240 |
| Avg. | 367 | 0.008 | 0.240 |

## *Georgia Power Company*
### *Plant Yates*
*Units Seven*
*June 27, 2001*

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 369 | 0.007 | 0.240 |
| Run 2 | 365 | 0.006 | 0.240 |
| Run 3 | 369 | 0.005 | 0.240 |
| Avg. | 368 | 0.006 | 0.240 |



05/06/2003 12:59 CLEMENTS&SWEET,PC → 15108450983 NO.707 D005

# III. Test Methods and Sampling Procedures

## Particulate

The sampling train that was used for execution of the particulate testing was manufactured by APEX Instruments, in Apex, North Carolina . The train meets all specifications as outlined by the U.S. Environmental Protection Agency.

As specified in the various test methods, all necessary calibrations on the dry gas meter, sampling tip, pitot tubes, thermocouples, and aneroid barometer were performed. The results of the calibrations are included in the Appendix.

The number of sample points and the sampling location were determined according to EPA Method 1. The test location and nearest disturbances (upstream and downstream) from the test site can be found in detail on the preliminary sample traverse data sheet in the Appendix.

EPA Method 2 was used to determine the stack gas velocity and volumetric flow rate. An S- type pitot tube was used in conjunction with an inclined oil gauge manometer. After each test repetition, a leak check was performed on the pitot manometer assembly and indicated no leak for 15 seconds.

Dry molecular weight was determined according to EPA Method 3 during each repetition by orsat analysis of integrated gas samples. The results of these analyses were reported on the field data sheets and in the Appendix.

US EPA Method 17, Determination of Particulate Emissions from Stationary Sources, was used to determine particulate concentrations. The sampling train consisted of a calibrated stainless steel nozzle, stainless steel in-stack filter holder, glass fiber filter, stainless steel probe, four impingers, 50' umbilical cord, pump, dry gas meter, and orifice.



05/06/2003 12:59 CLEMENTS&SWEET,PC → 15108450983 NO.707 P006

Before each test, filter holder with filter was secured to the end of the probe. In each of the first two impingers was placed 100 milliliters of water. The third impinger was left empty, and the fourth impinger was loaded with 200.0 grams of silica gel. Before each repetition, an optional leak check was performed to ensure all connections are secure.

The probe was inserted into the stack at the first sample traverse point. The stack gas parameters were recorded on the field data sheet, the pump turned on, and the sampling rate set at the isokinetic rate. At the end of the sampling period for the first point, the probe was moved to the next traverse point, and the sampling rate adjusted to maintain the isokinetic rate for the measured gas parameters at that point. This procedure was followed until all of the traverse points had been sampled. At each point, the following information was measured and recorded on the field data sheet: dry gas meter volume, stack gas velocity pressure differential, orifice meter pressure differential, stack gas temperature, sample train filtration temperature, filter outlet temperature, impinger train exit temperature, dry gas meter inlet and outlet temperature, and sample train system vacuum. After all of the points had been sampled, the pump was turned off and the probe was removed from the stack.

Immediately following each repetition, a leak check was performed on the sample train and indicated less than the allowable 0.02 CFM. The train was then disassembled. The filter holder assembly was first removed and recovered for later weighing. Next the nozzle was flushed with acetone and the catch stored. Next, the moisture catch from impingers one, two, and three were measured with a graduated cylinder. The silica gel from the fourth impinger was removed and weighed. The impingers were then reloaded as previously described.

After the test was completed, the filter and catches were returned to the laboratory. The filter containers were desiccated for a minimum of 24 hours, then weighed to a constant weight. The contents of each aceton nozzle wash bottle were transferred to tared beakers. The containers were then rinsed with acetone to ensure that all of the particulate matter was recovered. Each wash was evaporated at ambient temperature and pressure in the SSI laboratory. The evaporation was closely supervised to prevent "bumping" and subsequent loss of sample. Each beaker, with residue, was desiccated and weighed to the nearest 0.1 milligram.



05/06/2003 12:59 CLEMENTS&SWEET,PC → 15108450983 NO.707 P007

# IV. Statement of Authenticity

The sampling and analysis for this report was carried out under my direction and supervision. I have reviewed the testing details and results of this report and hereby certify that the data contained within is authentic and accurate to the best of my knowledge.

Date: 7/3/01

Signature: Jimmy Garrett
Testing Engineer



05/06/2003 12:59 CLEMENTS&SWEET,PC → 15108450983 NO.707 D008

# Compliance Particulate Emissions Testing

**Performed at**
**Georgia Power Company**
**Plant Hammond**
**Unit Four**
**Coosa, Georgia**

**Submitted By:**

**Spectrum Systems Inc.**
**3410 W. Nine Mile Road**
**Pensacola, Florida 32526**

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# I. Introduction

Spectrum Systems, Inc. of Pensacola, Florida was contracted by the Georgia Power Company in Atlanta, Georgia for the purpose of performing particulate emissions compliance testing. The testing was performed on July 07, 1998, on Unit Four at Plant Hammond in Coosa, Georgia. The purpose of testing these sources was to confirm that they are in compliance with the regulations set for by the USEPA and the Georgia Department of Natural Resources, Environmental Protection Division. USEPA Method 5 was utilized for quantifying particulate emissions.

Greg Rollins and Ron Cooley of Spectrum Systems, Inc. performed the particulate testing. Clark Mitchell of Georgia Power Company coordinated the testing. Spectrum Systems would like to thank Mr. Mitchell and the Plant Hammond personnel for their cooperation throughout the testing process.

# II. Summary of Results

Below are shown the results from testing performed on Unit Four at Plant Hammond. Shown in tabular form is the Unit's Generation in Megawatts, the Emission Rate in pounds per million Btu's (#/MMBtu), and the Allowable Rate in pounds per million Btu's (#/MMBtu).

***Georgia Power Company***
***Plant Hammond***
***Unit Four***
***July 07, 1998***

| Run No. | Unit Generation (Megawatts) | Emission Rate (#/MMBtu) | Allowable (#/MMBtu) |
|---|---|---|---|
| Run 1 | 530 | 0.007 | 0.240 |
| Run 2 | 530 | 0.010 | 0.240 |
| Run 3 | 530 | 0.007 | 0.240 |
| Avg. | 530 | 0.008 | 0.240 |

# III. Test Methods and Sampling Procedures

## Particulate

The sampling train that was used for execution of the particulate testing was manufactured by APEX Instruments, in Apex, North Carolina . The train meets all specifications as outlined by the U.S. Environmental Protection Agency.

As specified in the various test methods, all necessary calibrations on the dry gas meter, sampling tip, pitot tubes, thermocouples, and aneroid barometer were performed. The results of the calibrations are included in the Appendix.

The number of sample points and the sampling location were determined according to EPA Method 1. The test location and nearest disturbances (upstream and downstream) from the test site can be found in detail on the preliminary sample traverse data sheet in the Appendix.

EPA Method 2 was used to determine the stack gas velocity and volumetric flow rate. An S- type pitot tube was used in conjunction with an inclined oil gauge manometer. After each test repetition, a leak check was performed on the pitot manometer assembly and indicated no leak for 15 seconds.

Dry molecular weight was determined according to EPA Method 3 during each repetition by orsat analysis of integrated gas samples. The results of these analyses were reported on the field data sheets and in the Appendix.

US EPA Method 5, Determination of Particulate Emissions from Stationary Sources, was used to determine particulate concentrations. The sampling train consisted of a calibrated stainless steel nozzle, probe with heated stainless steel liner, glass fiber filter and filter holder in which the filter outlet temperature could be monitored, four impingers, 50' umbilical cord, pump, dry gas meter, and orifice.

Before each test, the probe and filter holder assemblies are secured in the filter box. In each of the first two impingers was placed 100 milliliters of water. The third impinger was left empty, and the fourth impinger was loaded with 200.0 grams of silica gel. Before each repetition, an optional leak check was performed to ensure all connections are secure.

After the probe and filter heaters warmed up to the specified operating temperature, the probe was inserted into the stack at the first sample traverse point. The stack gas parameters were recorded on the field data sheet, the pump turned on, and the sampling rate set at the isokinetic rate. At the end of the sampling period for the first point, the probe was moved to the next traverse point, and the sampling rate adjusted to maintain the isokinetic rate for the measured gas parameters at that point. This procedure was followed until all of the traverse points had been sampled. At each point, the following information was measured and recorded on the field data sheet: dry gas meter volume, stack gas velocity pressure differential, orifice meter pressure differential, stack gas temperature, sample train filtration temperature, filter outlet temperature, impinger train exit temperature, dry gas meter inlet and outlet temperature, and sample train system vacuum. After all of the points had been sampled, the pump was turned off and the probe was removed from the stack.

Immediately following each repetition, a leak check was performed on the sample train and indicated less than the allowable 0.02 CFM. The train was then disassembled. The filter holder assembly was first removed and recovered for later weighing. Next the probe and nozzle was flushed with acetone and the catch stored. Next, the moisture catch from impingers one, two,

and three were measured with a graduated cylinder. The silica gel from the fourth impinger was removed and weighed. The impingers were then reloaded as previously described.

After the test was completed, the filter and catches were returned to the laboratory. The filter containers were desiccated for a minimum of 24 hours, then weighed to a constant weight. The contents of each probe wash bottle were transferred to tared beakers. The containers were then rinsed with either acetone or water to ensure that all of the particulate matter was recovered. Each wash was evaporated at ambient temperature and pressure in the SSI laboratory. The evaporation was closely supervised to prevent "bumping" and subsequent loss of sample. Each beaker, with residue, was desiccated and weighed to the nearest 0.1 milligram.US EPA Method

# IV. Statement of Authenticity

The sampling and analysis for this report was carried out under my direction and supervision. I have reviewed the testing details and results of this report and hereby certify that the data contained within is authentic and accurate to the best of my knowledge.

Date: 072398

Signature:
Gregory D. Rollins
Testing Engineer

October 23, 1997

MEMORANDUM

SUBJECT: Interim Implementation of New Source Review Requirements for PM2.5

FROM: John S. Seitz, Director Office of Air Quality Planning & Standards (MD-10)

TO: See Addressees

This memorandum addresses the interim use of PM10 as a surrogate for PM2.5 in meeting new source review (NSR) requirements under the Clean Air Act (Act), including the permit programs for prevention of significant deterioration of air quality (PSD). The revised national ambient air quality standards (NAAQS) for particulate matter, which include the revised NAAQS for PM10 and new NAAQS for PM2.5, became effective on September 16, 1997. In view of the significant technical difficulties that now exist with respect to PM2.5 monitoring, emissions estimation, and modeling (described below), EPA believes that PM10 may properly be used as a surrogate for PM2.5 in meeting NSR requirements until these difficulties are resolved. The EPA's views on implementing the ozone and PM10 NAAQS during the interim period following the effective date of the new 8-hour ozone and revised PM10 NAAQS will be set forth in a separate EPA memorandum.

Section 165(a)(1) of the Act provides that no new or modified major source may be constructed without a PSD permit. Moreover, section 165(a)(3) provides that the emissions from any such source may not cause or contribute to a violation of any NAAQS. Also, section 165(a)(4) requires best available control technology for each pollutant subject to regulation under the Act. The EPA's recent promulgation of the primary and secondary standards for PM2.5 marks the first time that EPA has specifically regulated fine particles--less than 2.5 microns in diameter--as a discrete indicator for particulate matter. Hence, this memorandum addresses how to implement PSD for PM2.5 in light of significant technical difficulties which presently exist.

Of specific concern is the lack of necessary tools to calculate emissions of PM2.5 and related precursors and project ambient air quality impacts so that sources and permitting authorities can adequately meet the NSR requirements for PM2.5. Any comprehensive system for regulating PM2.5 must take into account not only the fine particles emitted directly by stationary sources but also the various precursors, emitted by certain sources, which result in secondarily-formed fine particles through chemical reactions in the atmosphere. Recent studies suggest that secondary particulate matter may account for over half of total ambient PM2.5 nationwide. Emissions factors for the fine particles emitted directly by stationary sources, and for some important precursors (e.g., ammonia), are largely unavailable at the present time.

The EPA is in the process of developing a comprehensive modeling system which will be designed to include precursor emissions and account for secondary fine particle formation. The modeling system will also incorporate a method for nesting small local impacts from individual point sources within a greater modeling domain. Before this can be completed, it will be necessary to collect sufficient monitoring data to verify and validate protocol modeling results.

Ambient monitoring for PSD purposes must be collected from appropriately designed monitors. Sufficient quantities of such monitors will not be available specifically for PSD monitoring purposes in the near future. Initially, as these monitors become available, they will be needed to establish the new monitoring stations for the national network of PM2.5 sites, including the required core PM2.5 State and local air monitoring stations. A high priority has been placed on the establishment of the necessary PM2.5 monitoring sites nationwide so that the information from these sites can be analyzed and evaluated in order to establish plans and priorities for implementing the PM2.5 NAAQS, including the promulgation of section 107 designations.

For the reasons stated above, EPA believes that it is administratively impracticable at this time to require sources and State permitting authorities to attempt to implement PSD permitting for PM2.5. The EPA has projects underway that will address the current technical and informational deficiencies, but it will take 3-5 years to complete these projects. Until these deficiencies are corrected, EPA believes that sources should continue to meet PSD and NSR program requirements for controlling PM10 emissions (and, in the case of PM10 nonattainment areas, offsetting emissions) and for analyzing impacts on PM10 air quality. Meeting these measures in the interim will serve as a surrogate approach for reducing PM2.5 emissions and protecting air quality.

This memorandum presents EPA's views on the issues associated with implementation of the new PM2.5 NAAQS under Federal, State and local NSR programs. The statements do not bind State and local governments and the public as a matter of law. When the technical difficulties are resolved, EPA will amend the PSD regulations under 40 CFR 51.166 and 52.21 to establish a PM2.5 significant emissions rate, and EPA will also promulgate other appropriate regulatory measures pertinent to PM2.5 and its precursors. Because the earliest date on which PM2.5 nonattainment areas will be designated is in 2002, and nonattainment NSR does not apply until after

nonattainment designations are made, implementation of the nonattainment NSR requirements under part D of title I of the Act need not be addressed at this time.

If you have any questions concerning this memorandum or wish to address any issues raised herein, please contact Dan deRoeck at (919) 541-5593.

Addressees: Director, Office of Ecosystem Protection, Region I
Director, Division of Environmental Planning and Protection, Region II
Director, Air, Radiation, and Toxics Division, Region III
Director, Air, Pesticides, and Toxics Management Division, Region IV
Director, Air and Radiation Division, Region V
Director, Multimedia Planning and Permitting Division, Region VI
Director, Air, RCRA, and Toxics Division, Region VII
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Director, Air and Toxics Division, Region IX
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cc: New Source Review Contacts
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Dan deRoeck (MD-12)
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Sally Shaver (MD-15)

MEMORANDUM

SUBJECT: Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas

FROM: Stephen D. Page
Director

TO: See Addressees

**What is the purpose of this memorandum?**

This memorandum provides guidance on the implementation of the major New Source Review (NSR) provisions under title 1, Part D of the Clean Air Act (Act) in fine particulate (PM-2.5) nonattainment areas in the interim period between the effective date of the PM-2.5 National Ambient Air Quality Standard (NAAQS) designations (April 5, 2005) and when we promulgate regulations to implement nonattainment major NSR for the PM-2.5 NAAQS. This memorandum also re-affirms the Memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, *Interim Implementation of New Source Review for PM2.5* (Oct. 23, 1997) that applies in Prevention of Significant Deterioration of Air Quality (PSD) programs for PM-2.5 attainment and unclassifiable areas.

**Why are we issuing this memorandum?**

On January 5, 2005, we promulgated nonattainment designations for the PM-2.5 NAAQS. These designations become effective on April 5, 2005. *See* 70 FR 944. Under Section 172(b) of the Clean Air Act (Act), the Administrator may provide States up to 3 years from the effective date of designations to submit State Implementation Plan (SIP) revisions meeting the applicable nonattainment requirements. In the near future, we plan to issue a proposed and final rule setting forth the schedule for these plan submissions. We also plan to establish the requirements that State and local agencies (States) and Tribes must meet in their implementation plans for attainment of the PM-2.5 NAAQS including provisions to address the major NSR requirements of title I, Part D of the Act (nonattainment major NSR program). Notwithstanding the absence of these implementing regulations, we interpret Section 172(c)(5) of the Act to require States to issue major New Source Review (NSR) permits for the construction and major modifications of major stationary sources located in any nonattainment area. Accordingly, once nonattainment designations for PM-2.5 become effective on April 5, 2005, States must issue major NSR permits that address the Section 173, nonattainment major NSR requirements for PM-2.5. We are issuing this memorandum to address how States should implement major NSR for PM-2.5 until we promulgate the PM-2.5 implementation rule.

**What applies in PM-2.5 nonattainment areas?**

During the SIP development period, EPA generally requires States to issue major NSR permits using the authority of States' approved nonattainment major NSR programs (to the extent these provisions apply automatically to the pollutant ) or using the authority of 40 CFR Part 51, Appendix S (where a State lacks a nonattainment major NSR program covering the pollutant.) [1] However, in this case, the absence of a final PM-2.5 implementation rule makes administering a PM-2.5 nonattainment major NSR program infeasible. Accordingly, until we promulgate the PM-2.5 major NSR regulations, States should use a PM-10 nonattainment major NSR program as a surrogate to address the requirements of nonattainment major NSR for the PM-2.5 NAAQS. By applying a PM-10 nonattainment major NSR program in the interim period, States will effectively mitigate increases in PM-2.5 emissions and protect air quality because PM-2.5 is a subset of PM-10 emissions.

Using the surrogate PM-2.5 nonattainment major NSR program, States should assume that a major stationary source's PM-10 emissions represent PM-2.5 emissions and regulate these emissions using either Appendix S or the State's SIP-approved nonattainment major NSR program for PM-10. In most cases, we believe that States will need to rely on Appendix S for authority to issue permits during this interim period, because their existing State programs are not designed to accommodate the surrogate PM-2.5 nonattainment major NSR program.[2] Moreover, we expect that most States will need to implement a transitional PM-2.5 nonattainment major NSR program under Appendix S even after we finalize the PM-2.5 implementation rule until EPA approves changes to the States' SIP programs.

**What is the major stationary source threshold and offset ratio under the surrogate PM-2.5 nonattainment major NSR program?**

Section 302(j) defines a major stationary source as any source that emits or has the potential to emit 100 tpy of any regulated pollutant, and Section 173(c) of the Act requires major stationary sources to offset emissions increases resulting from construction or major modifications in a ratio of at least 1 to 1. Appendix S and the majority of SIP-approved PM-10 nonattainment major NSR programs apply this major source threshold and corresponding offset requirement. Accordingly, these provisions should be used to define the major stationary source threshold and offset ratio for the surrogate PM-2.5 nonattainment major NSR program. This means that during the interim period, a source is major for PM-2.5 if it emits or has the potential

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[1]The terms of 40 CFR 52.24(k), Appendix S of Part 51 provide provisions for a transitional nonattainment major NSR program until we approve a State's Part D major NSR program into the SIP.

[2]If a State lacks authority to issue a major NSR permit consistent with these requirements, then EPA will issue the permit under the authority of 40 CFR 52.24(k) and Appendix S.

to emit 100 tpy of PM-10.[3] A State that uses its SIP-approved PM-10 program as a surrogate PM-2.5 program need not apply the separate major stationary source level for serious PM-10 nonattainment areas in the surrogate PM-2.5 program. We do not interpret the specific PM-10 requirements of Part D, Subpart 4 of the Clean Air Act to apply to PM-2.5 and do not believe they should be applied under a surrogate PM-2.5 nonattainment major NSR program.

For any major stationary source whose particulate emissions are predominantly coarse particulate (particulate matter that ranges in size between PM-10 and PM-2.5), assuming that all of the source's PM-10 emissions represent the source's PM-2.5 emissions could inappropriately trigger nonattainment major NSR for PM-2.5. To avoid such an outcome, a source may quantify its PM-2.5 fraction. One approach is to apply two test methods in series - Conditional Test Method 40 (which adds a PM-2.5 cyclone separator between the Method 201A cyclone and filter) followed by the Method 202 sampler to collect condensible materials. The sum of the PM mass in these two fractions (i.e., the Conditional Test Method 40 filterable mass plus the Method 202 condensible mass) represents the primary PM-2.5 emissions from the source for the test period. Under appropriate circumstances (e.g., construction of a new unit, where it is not possible to conduct testing prior to start up), testing of similar existing units can be an appropriate means of obtaining relevant emissions data. Also, other approaches for quantifying PM-2.5 emissions besides the testing methods described above would be considered where they can be shown to produce reliable data.

If the source demonstrates that it is not a major stationary source for PM-2.5, then the nonattainment major NSR provisions for PM-2.5 need not be applied to the source. Conversely, if a source is major for PM-10 and does not quantify its PM-2.5 emissions, then States should presume that the source is major for PM-2.5 and subject it to the surrogate PM-2.5 nonattainment major NSR program if it constructs a major stationary source or undergoes a major modification.

**What is the significant emissions rate for the surrogate PM-2.5 nonattainment major NSR program?**

On July 1, 1987, we established a significant emissions rate for PM-10 of 15 tpy. *See* 52 FR 24683. States should use this rate for the surrogate PM-2.5 program. At the time we established the 15 tpy significant emissions rate, we amended only our PSD regulations to incorporate the PM-10 value because the PM-10 NAAQS did not yet apply to nonattainment areas. Nonetheless, we established the PM-10 significant emissions rate through notice and

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[3]The definition of PM-10 includes condensible particulate matter. For a detailed discussion of condensible particulate matter, see the General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990 (April 16, 1992, 57 FR 13542).

comment rulemaking; and, accordingly, the same value should apply for PM-10 under Appendix S and State SIP-approved programs in the interim period.[4]

**Will any precursors be regulated under the surrogate PM-2.5 nonattainment major NSR program?**

Not at this time. Section 302 (g) includes precursors to the formation of any air pollutant within the term "air pollutant" to the extent the Administrator identifies the precursors for the particular purpose for which the term "air pollutant" is used. To date, the Administrator has not identified any precursors to the formation of PM-2.5 for purposes of the major NSR program. On November 5, 2003, the Administrator proposed to require that regional emissions analysis for the purposes of transportation conformity under Section 176(c) of the Act include certain precursors (68 FR 62690). In the Clean Air Interstate Rule, we require states to reduce emissions of NOx and SO2 on the grounds that they are precursors for PM-2.5. However, several novel issues need to be resolved before the NSR program can be applied to PM-2.5 precursors (e.g., how many SO2 or NOx offsets will be needed to accommodate the fine particles formed by these constituents; can SO2 emissions reductions be used to offset NOx emissions, and vice versa). We plan to request comment on regulating these pollutants and other potential PM-2.5 precursors for purposes of major NSR in the PM-2.5 implementation rule.

**What major NSR requirements apply in PM-2.5 attainment and unclassifiable areas?**

The revised NAAQS for particulate matter, which include the revised NAAQS for PM-10 and new NAAQS for PM-2.5, became effective on September 16, 1997. On October, 23, 1997, we issued a memorandum addressing the interim use of PM-10 as a surrogate for PM-2.5 in meeting Prevention of Significant Deterioration of Air Quality Program (PSD) provisions for PM-2.5 as required by title 1, Part C of the Act. *See* Memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, *Interim Implementation of New Source Review for PM2.5* (Oct. 23, 1997). This memorandum referenced provisions of Part C of the Act which we interpret to require PSD permits for PM-2.5 upon the effective date of the PM-2.5 NAAQS, and identified significant technical difficulties with implementing PSD for PM-2.5 because of limitations in ambient monitoring and modeling capabilities. Because we have not promulgated the PM-2.5 implementation rule, administration of a PM-2.5 PSD program remains impractical. Accordingly, States should continue to follow the October 23, 1997, guidance for PSD requirements.

This memorandum presents EPA's policy on the implementation of major NSR requirements until EPA promulgates a final PM-2.5 implementation rule. The statements in this policy guidance do not bind State and local governments and the public as a matter of law.

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[4] We intend to issue a final rule adding a PM-10 significant emissions rate of 15 tpy to Appendix S in a forthcoming rulemaking.

If you have any questions concerning this memorandum, please contact Raj Rao at (919) 541-5344, or Lynn Hutchinson at (919) 541-5795.

Addresees:
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OAQPS:ITPID:R.Rao/mlt:C304-02:919-541-5536/Regional Air Directors

# CTDEP INTERIM PM2.5 NEW SOURCE REVIEW MODELING POLICY AND PROCEDURES

## Policy Considerations

Effective December 15, 2006, the U.S. Environmental Protection Agency (EPA) revised the national ambient air quality standards (NAAQS) for particulate matter less than 2.5 microns (PM2.5), retaining the annual standard of 15 $\mu g/m^3$and tightening the 24-hour average to 35 $\mu g/m^3$. Connecticut has monitored ambient levels of PM2.5 considerably higher than 35 $\mu g/m^3$, a concern as the revised standard is set to better protect public health. While EPA has not yet fully provided implementation rules or guidance for these revised standards, the Connecticut Department of Environmental Protection (CTDEP) is developing strategies and implementing procedures to better protect public health and to help provide for attainment of both the 1997 and 2006 revised PM2.5 NAAQS.

This interim policy describes CTDEP's requirements for new source review (NSR) permitting and modeling for sources of PM2.5. In particular, for permit applications subject to this policy, a demonstration of compliance with the PM10 NAAQS will no longer serve as a surrogate for compliance with the PM2.5 NAAQS. Instead, NSR permit applicants must consider PM2.5 as a criteria pollutant and address it in preparing an application. These interim procedures will serve the policy goal of public health protection by minimizing PM2.5 ambient air impacts from new stationary sources, particularly in Fairfield and New Haven Counties, which are designated as nonattainment for PM2.5.

This interim policy applies immediately to applications for NSR permits or modifications for which a tentative determination has not been issued. These procedures will be in effect until CTDEP adopts a regulation, a State Implementation Plan revision, or a revised policy addressing the PM2.5 NAAQS.

## New Source Review Permitting

Except as noted below, this policy applies a "business as usual" approach to taking PM2.5 into account in CTDEP NSR technology reviews and any necessary requirements to reduce PM2.5 impacts.

**Nonattainment review.** Although EPA has not yet made designations of nonattainment for the 2006 24-hour PM2.5 NAAQS, Fairfield and New Haven Counties are designated as nonattainment for the 1997 annual PM2.5 NAAQS. The remainder of Connecticut is currently designated as attainment for PM2.5. Permit applicants should assume that these geographic boundaries would also apply to the 2006 24-hour PM2.5 NAAQS. See Figure 1 for a map of the assumed designations. New major stationary sources in nonattainment areas are required by the Clean Air Act to install technology deemed to produce the lowest achievable emission rate (LAER). Also, new major stationary sources and major modifications are required to offset emissions increases at a ratio of at least 1:1 from other sources located in the nonattainment area. Since $SO_2$ is a precursor to PM2.5, offsetting emissions of $SO_2$ at a greater than 1:1 ratio may be substituted for PM2.5 on a case-by-case basis. The source must provide a sound technical justification, which demonstrates that any proposed $SO_2$ offset will provide a net air quality benefit equal to or greater than a 1:1 PM2.5 offset.

**PM2.5 emission limits.** A permit applicant may assume PM2.5 emissions are equivalent to PM10 emissions or propose a PM2.5-specific emission limit based on supporting data. Applications should include separate emission estimates for filterable and condensable fractions of expected total PM2.5 emissions. Sources will be required to meet the filterable fraction using appropriate EPA reference stack test methods. A source will not be required to demonstrate compliance with an expected condensable emission limit until one year after the U.S. EPA promulgates a new reference stack test method for the condensable fraction. At that time, the PM2.5 emissions will be evaluated and the permit will be modified to reflect the results of the stack test for condensables.

## New Source Review Modeling

Applications for new sources with potential PM2.5 emissions in excess of 15 tons per year must include an adequate PM2.5 modeling analysis to demonstrate compliance with both the PM2.5 NAAQS of 15 $\mu g/m^3$ (annual average) and 35 $\mu g/m^3$ (24-hour average). CTDEP's modeling procedures typically used in the NSR application process are unchanged, except for the addition of PM2.5 as a pollutant to be assessed. The procedures for different source situations are summarized in Figure 2. The specific criteria to apply in performing a PM2.5 modeling demonstration are described below.

**Applicability thresholds.** The modeling applicability thresholds apply to any new stationary source or modification subject to the provisions of sections 22a-174-2a and 22a-174-3a of the Regulations of Connecticut State Agencies (R.C.S.A.), including:

- New major PM2.5 sources (100 tons per year or more);
- Proposed modifications to existing major PM2.5 sources (100 tons per year or more) with a PM2.5 net emissions increase of equal to or more than 15 tons per year; and
- New minor sources or modifications with a proposed PM2.5 net emissions increase greater than 15 tons per year but less than 100 tons per year.

Any new source or modification that is required to receive a NSR permit, with a net PM2.5 emission increase of $\geq$3.0 tpy but < 15 tpy, should follow existing screening modeling procedures for PM. PM10 emissions can be used as a surrogate for PM2.5.

**Background air quality.** CTDEP's existing ambient PM2.5 monitoring network may be used to estimate background PM2.5 levels for all locations in Connecticut. The annual background PM2.5 value should be based on the average of the most recent three years of available data. The 24-hour background PM2.5 value should be based on the average of the 98$^{th}$ percentile 24-hour values measured over the last three years of available data. An applicant may choose to develop a more refined background PM2.5 value by performing a full year of on-site pre-construction monitoring. CTDEP may allow an applicant to define background values that are less than the observed design values, provided that the applicant provides sound technical reasoning for such an approach (e.g., a directional-specific analysis of monitored levels).

**Ambient air quality modeling.** Applications requiring air quality modeling must demonstrate expected compliance with the PM2.5 NAAQS based on a total expected PM2.5 emission rate that includes both filterable and condensable PM2.5.

When calculating impacts for comparison to the annual NAAQS of 15 $\mu g/m^3$, the maximum three-year average of annual PM2.5 predicted impacts from the new source at each receptor over the five years modeled should be added to the monitored background concentration. When calculating impacts for comparison to the 24-hour NAAQS of 35 $\mu g/m^3$, the three-year average of the yearly maximum 8$^{th}$ high 24-hour PM2.5 predictions at each receptor should be added to the monitored background concentration and the result compared to the NAAQS.

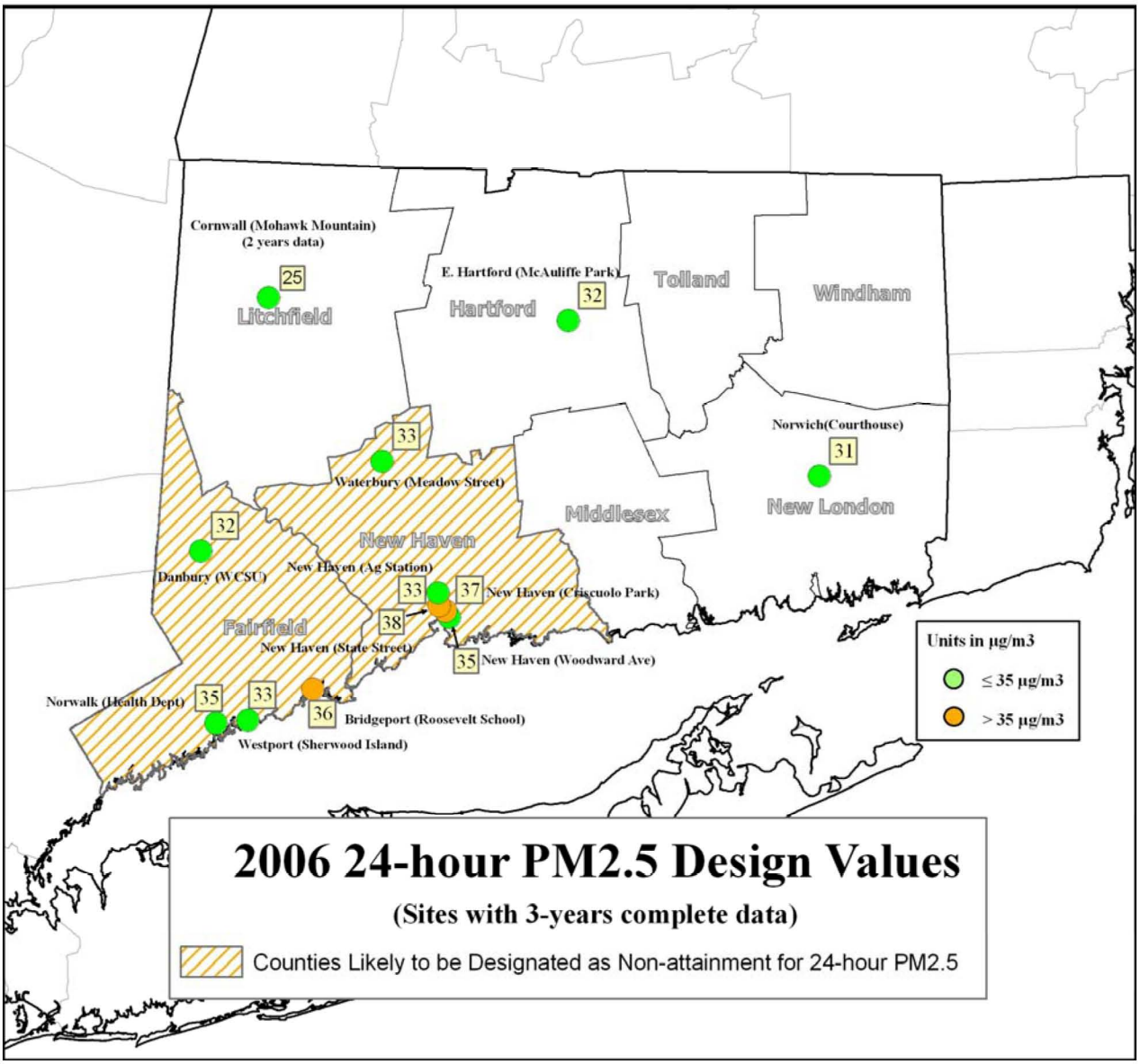
CTDEP is adopting the PM2.5 significant impact levels (SILs) recommended by the Northeast States for Air Use Management (NESCAUM) of 0.30 $\mu g/m^3$ (annual average) and 2.0 $\mu g/m^3$ (24-hour average). Background information regarding the selection of these SILs is available at http://www.nescaum.org/topics/permit-modeling.

Questions concerning the PM2.5 modeling procedures should be directed to Jude Catalano at 860-424-3384 or jude.catalano@po.state.ct.us. The regulations that apply to NSR permitting, namely R.C.S.A. sections 22a-174-2a and 22a-174-3a, are available at: http://www.ct.gov/dep/cwp/view.asp?a=2684&q=322184&depNav_GID=1619.

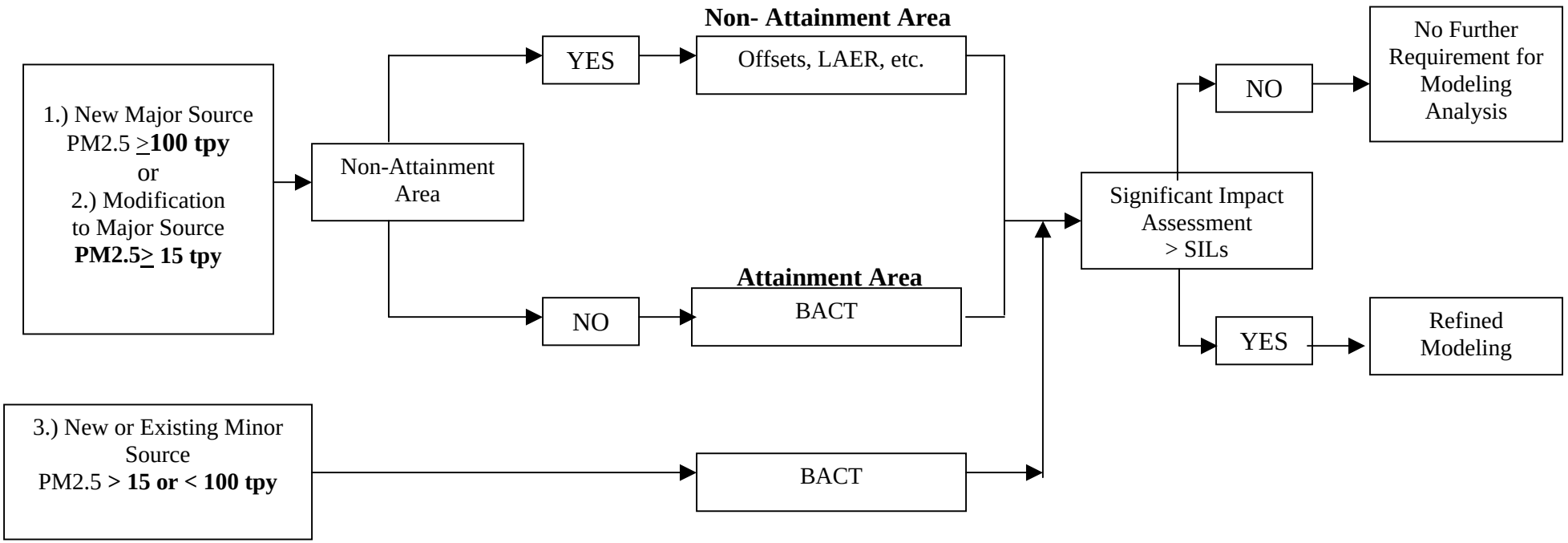
Gina McCarthy
Commissioner, CTDEP

8/21/07
Date

**Figure 1. PM2.5 nonattainment area boundaries for the 24-hr NAAQS are likely to be the same as for annual NAAQS.**



# Figure 2. PM-2.5 NSR FLOW DIAGRAM



http://www.epa.gov/ttn/emc/ctm.html
Last updated on Wednesday, August 29th, 2007.

Technology Transfer Network
Emission Measurement Center



# Conditional Test Methods

*Go to Explanation of File Type Icons*

| File Description | File Name | Posting Date | File Types |
|---|---|---|---|
| Butadiene Method | CTM-001.WPD | 4-27-98 | |
| Butadiene Method (PDF format) | CTM-001.PDF | 4-27-98 | |
| Particulate (PM Screening) Method. | CTM-002.WPD | 4-27-98 | |
| Particulate (PM Screening) Method (PDF format). | CTM-002.PDF | 4-27-98 | |
| Particulate (PM Screening) Figure. | CTM02FIG.WPD | 4-27-98 | |
| Particulate (PM Screening) Figure (PDF format). | CTM02FIG.PDF | 4-27-98 | |
| Particulate (PM Modified High Vol.) Method. | CTM-003.WPD | 4-27-98 | |
| Particulate (PM Modified High Vol.) Method (PDF format). | CTM-003.PDF | 4-27-98 | |
| Conditional Test Method for Acrylonitrile. (PDF format). | CTM-008.PDF | 4-27-98 | |
| CTM-010 Figure 2 (Freelance). | CTM010F2.PRE | 4-27-98 | |
| CTM-010 Figure 1 (Freelance). | CTM010F1.PRE | 4-27-98 | |
| Perchloroethylene in Wet Waste (Filters and Still Bottoms). | CTM-010.WPD | 4-27-98 | |
| Perchloroethylene in Wet Waste (Filters and Still Bottoms) (PDF format). | CTM-010.PDF | 4-27-98 | |
| Halogenated Organics Method. | CTM-011.WPD | 4-27-98 | |
| Halogenated Organics Method (PDF format). | CTM-011.PDF | 4-27-98 | |
| Controlled Condensation Method for Measuring Sulfuric Acid Emissions from Kraft Recovery Furnaces. | CTM-013.PDF | | |

| | | |
|---|---|---|
| Modified Controlled Condensation Method for Measuring Sulfuric Acid Emissions from Kraft Recovery Furnaces and Boilers with Dry Particulate Matter Control Devices. | CTM-013A.PDF | |
| Modified Controlled Condensation Method for Measuring Sulfuric Acid Emissions from Kraft Recovery Furnaces and Boilers with Wet Particulate Matter Control Devices. | CTM-013B.PDF | |
| Benzene Matter Emissions. | CTM-014.WPD | 4-27-98 |
| Benzene Matter Emissions (PDF format). | CTM-014.PDF | 4-27-98 |
| Gas Velocity and Volumetric Flowrate under Cyclonic Flow Conditions. | CTM-019.WPD | 4-27-98 |
| Gas Velocity and Volumetric Flowrate under Cyclonic Flow Conditions (PDF format). | CTM-019.PDF | 4-27-98 |
| Nitric Oxide, Nitrogen Dioxide, & NOx emissions by Electrochemical Analyzer. | CTM-022.WPD | 4-27-98 |
| Nitric Oxide, Nitrogen Dioxide, & NOx emissions by Electrochemical Analyzer (PDF format). | CTM-022.PDF | 4-27-98 |
| Microbial Survivability Test for Medical Waste Incinerator Ash. | CTM-025.WPD | 4-27-98 |
| Microbial Survivability Test for Medical Waste Incinerator Ash. (PDF format). | CTM-025.PDF | 4-27-98 |
| Microbial Survivability Test for Medical Waste Incinerator Emissions. | CTM-026.WPD | 4-27-98 |
| Microbial Survivability Test for Medical Waste Incinerator Emissions (PDF format). | CTM-026.PDF | 4-27-98 |
| Screening Method for Air Toxics Emission Factors. | SCREEN.ZIP | 4-27-98 |
| Screening Method for Air Toxics Emission Factors (PDF format). | SCREPDF.ZIP | 4-27-98 |
| Procedure for Collection and Analysis of Ammonia in Stationary Sources. | CTM-027.WPD | 4-27-98 |
| Procedure for Collection and Analysis of Ammonia in Stationary Sources (PDF format). | CTM-027.PDF | 4-27-98 |
| Direct Interface GC/MS Performance-Based Method (10/28/97). | CTM-028.PDF | 4-27-98 |
| CARB Method 435-Asbestos in Serpentine Aggregate. | CTM-029.WPD | 4-27-98 |
| CARB Method 435-Asbestos in Serpentine Aggregate (Adobe format). | CTM-029.PDF | 4-27-98 |

CTM-030 Note: Please note there is a Consensus based ASTM Method (ASTM D6522-00) that is similar to this conditional test method and we strongly encourage you to consider it's use in accordance with the applicability as specified in the method.

| | | | |
|---|---|---|---|
| Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers and Process Heaters Using Portable Analyzers. | CTM-030.PDF | 10/13/97 | |
| Screening Method for Methylene Diphenyl Diisocyanate (MDI) (PDF format). | CTM-031.PDF | 3-17-99 | |
| Draft Method for Sampling and Analysis for High Levels of Phenol and Cresol Emissions From Stationary Sources | CTM-032.ZIP | 4-07-99 | |
| Draft Method for Sampling and Analysis for High Levels of Phenol and Cresol Emissions from Stationary Sources. | CTM-032.PDF | 4-07-99 | |
| Draft Method for Sampling and Analysis for Hydrogen Cyanide Emissions From Stationary Sources | CTM-033.WPD | 4-08-99 | |
| Draft Method for Sampling and Analysis of Hydrogen Cyanide Emissions from Stationary Sources. | CTM-033.PDF | 4-08-99 | |
| Draft Method for the Determination of O2, CO2 & (NO and NO2) for Periodic Monitoring | CTM-034.WPD | 10-12-99 | |
| Draft Method for the Determination of O2, CO2, & (NO and NO2) for Periodic Monitoring | CTM-034.PDF | 10-12-99 | |
| SCAQMD Method 25.3 - Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions From Clean Fueled Combustion Sources | CTM-035.PDF | 04/04/2000 | |
| (Revised 03/05) Method for Sampling Isocyanate Stack Emissions | CTM-036.PDF | 03/04/05 | |
| (Revised 03/05) Method for Analyzing Isocyanate Stack Emissions | CTM-036A.PDF | 03/04/05 | |
| Method for Measurement of Formaldehyde Emissions From Natural Gas-Fired Stationary Sources - Acetyl Acetone Derivitization Method" has been proposed as Method 323 | M-323.PDF | | |
| Measurement of Ammonia Emissions From Highway, Nonroad, and Stationary Use Diesel Engines by Extractive Fourier Transform Infrared (FTIR)Spectroscopy | CTM-038.PDF | 03/07/03 | |
| Measurement of PM 2.5 and PM 10 Emissions by Dilution Sampling (Constant Sampling Rate Procedures) Revised 7/04 | CTM-039.WPD | 09/30/04 | |
| Measurement of PM 2.5 and PM 10 Emissions by Dilution Sampling (Constant Sampling Rate Procedures) Revised 7/04 | CTM-039.PDF | 09/30/04 | |
| This Windows Media Movie provides a visualization of the hardware associated with the method described in Conditional Test Method 39. The file size of this movie is large (50Mb) and requires the Windows Media viewer. | DST TOUR.WMV | 06/03 | |

| | | | |
|---|---|---|---|
| DRAFT Method for Determination of PM10/PM2.5. | CTM-040.WPD | 03/12/03 | |
| DRAFT Method for Determination of PM10/PM2.5. | CTM-040.PDF | 03/12/03 | |
| Conditional Test Method - Determination of Volumetric Gas Flow in Rectangular Duct or Stacks Taking Into Account Velocity Decay Near the Stack or Duct Walls. | CTM-041.PDF | 11/30/04 | |
| Use of Flame Ionization Detector-Methane Cutter Analysis Systems for VOC Compliance Testing of Bakeries (Revised 08/04) | CTM-042.DOC | 09/03/04 | |
| Design Specifications for Opacity Monitors to be used Where Opacity Limits are less than 10 percent | CPS-001.PDF | 09/25/02 | |

## Fine Particulate Matter ("PM2.5") Monitoring Results-South Carolina

| Site Address | County | 2004-2006 Design Values | 2005-2007 Design Values | 2007 PM2.5 Annual Mean |
|---|---|---|---|---|
| 1407 King Street, Beaufort | Beaufort | 11.7 | 11.3 | 10.5 |
| 2670 Elms Plantation Blvd, N. Charleston | Charleston | 12.5 | 12.1 | 10.8 |
| 2670 Elms Plantation Blvd., N. Charleston | Charleston | 12.6 | 12 | 10.6 |
| 360 Fishburne Street, N. Charleston | Charleston | 11.8 | 11.1 | 9.8 |
| Rt 2 Box 100 McBee (Sc145) | Chesterfield | 12.7 | 12.4 | 11.8 |
| Woodyard Rd. | Edgefield Co | 13.4 | 13 | 11.9 |
| 3300 Thronblade Dr. | Florence | 12.7 | 12.5 | 11.8 |
| 400 Dozier St | Georgetown | 12.9 | 12.9 | 12.3 |
| 91 Wakefield St. (110 Thruston St.) | Greenville | 15.9 | 14.8 | 13.1 |
| 405 Brushy Creek Rd, Taylors | Greenville | 15.1 | 14.9 | 13.8 |
| Merrywood Rd., Greenwood | Greenwood | 13.7 | 13.3 | 12.1 |
| 632 18th Ave. N., Myrtle Beach | Horry | 11.9 | 11.4 | 10.8 |
| 200 Leisure Lane, Irmo | Lexington | 15.1 | 14.5 | 12.8 |
| Round Mnt. Tower Rd. (Long Creek, S) | Oconee | 11.0 | 10.8 | 9.6 |
| 8311 Parklane Rd, Columbia | Richland | 13.8 | 13.5 | 12.3 |
| 323 S. Bull Street, Columbia | Richland | 15.0 | 14.8 | 14.1 |
| 323 S. Bull Street, Columbia | Richland | 14.4 | 13.9 | 12.9 |
| 4200 Copper Line Rd. | Spartanburg | 14.4 | 13.8 | 12.2 |

Data obtained from DHEC (www.scdhec.gov) and EPA (www.epa.gov) websites; calculations and table created by Southern Environmental Law Center.

# Emissions of Sulfur Trioxide from Coal-fired Power Plants

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**Mercury, Trace Elements, and Particulate Matter**
**Orlando, FL**
**December 10-12, 2002**

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**Abstract**
Emissions of sulfur trioxide ($SO_3$) are a key component of plume opacity and acid deposition. Consequently, these emissions need to be low enough not to cause opacity violations and acid deposition. Generally, a small fraction of sulfur in coal is converted to $SO_3$ in coal-fired combustion devices such as electric utility boilers. The emissions of $SO_3$ from such a boiler depend on coal sulfur content, combustion conditions, flue gas characteristics, and air pollution devices being used. It is well known that the catalyst used in the selective catalytic reduction (SCR) technology for nitrogen oxides ($NO_x$) control oxidizes a small fraction of sulfur dioxide ($SO_2$) in the flue gas to $SO_3$. The extent of this oxidation depends on the catalyst formulation and SCR operating conditions. Gas-phase $SO_3$ and sulfuric acid ($H_2SO_4$), on being quenched in plant equipment (e.g., air preheater and wet scrubber), result in fine acidic mist, which can cause increased plume opacity and undesirable emissions. Recently, such effects have been observed at plants firing high-sulfur coal and equipped with SCR systems and wet scrubbers. This paper investigates the factors that affect acidic mist production in coal-fired electric utility boilers and discusses approaches for mitigating emission of this mist.

**Introduction**
As understanding of the adverse effects of air pollution has grown, so also have the complexity of coal fired power plant design and operation, especially with regard to air pollution control systems. Control of air pollutant emissions is not only a legal requirement, but is also becoming a financial necessity, as salability of effluents and trading of emissions permits increase the direct monetary value of emissions control. The days when one must only consider “the nuisance value of fly ash” are long past [Fryling, 1966].

As plant complexity has increased, so have unexpected consequences of changing segments of the total chemical process that occurs between fuel preparation and ultimate emissions. One of the more discernible adverse consequences is the formation and emission of $SO_3$, as highlighted by the recent and well-publicized experiences of a power plant in Ohio [Hawthorne, 2001]. Although not directly subject to emission limits, $SO_3$ is important to consider during the design and operation of coal-fired utility boilers for a number of environmental and plant performance reasons.

The formation of $SO_3$ will occur during the combustion of sulfur-bearing fuels such as coal and heavy fuel oils. For reasons that will be discussed below, concentrations of $SO_3$ in the boiler, stack, and/or plume can be high enough to cause adverse impacts to plant equipment and to the environment. Impacts on plant equipment can include corrosion, fouling, and plugging and may require additional hardware or changes in operation, including load limits, to minimize $SO_3$ concentrations and the resulting adverse impacts.

*Health and Environmental Effects*
Formation of visible $H_2SO_4$ droplets depends upon the concentration and dew point of $H_2SO_4$ and the concentration of sub-micron particle upon which the acid can condense. As seen in Figure 1, the $H_2SO_4$ dew point is a function of water vapor and $H_2SO_4$ concentration, and increases as both these variables increase [Verhoff and Banchero, 1974]. The curves in Figure 1 determine the fraction of $H_2SO_4$ in the vapor and condensed phases for temperatures below the

dew point. For example, a 250 °F flue gas with 10% water vapor and 8 ppm $H_2SO_4$ will have a vapor phase acid gas concentration of approximately 2 ppm, with the remaining 6 ppm in the condensed phase.

If temperatures at the stack are low enough and water vapor and $H_2SO_4$ concentrations are high enough, the condensed phase concentration of $H_2SO_4$ can be at a level that results in the formation of a visible plume attached to the stack. Once the gases leave the stack, the rate of cooling and subsequent $H_2SO_4$ condensation competes with the plume dilution by entrainment of ambient air into the plume. Even in cases where stack conditions are such that the $H_2SO_4$ is completely in the vapor phase at the stack exit, a detached plume may still form shortly downwind as temperatures drop below the dew point before concentrations fall below the point where $H_2SO_4$ condensation occurs.

In most cases, and particularly in the case where $H_2SO_4$, water, and sub-micron solid particles are present, condensation is the dominant formation mechanism. The opacity of these plumes is most strongly influenced by the concentrations of condensing species and sub-micron fly ash particles present in the stack gases. The size distribution of the sub-micron fly ash can also have a noticeable effect on plume opacity at low to moderate $H_2SO_4$ concentrations, as these particles act as condensation sites for the condensing vapor-phase $H_2SO_4$. The relationship between sub-micron particle concentration, $H_2SO_4$ concentration, and plume opacity is shown in Figure 2 for flue gas with a sub-micron particle mode at 0.15 µm diameter [Damle et al., 1984, 1987]. The gray area denotes a typical range of sub-micron particle concentrations downstream of an ESP [Markowski et al., 1980].

The curves in Figure 2 illustrate that $H_2SO_4$ concentration can have a strong impact on opacity when fine particle concentrations are present at realistic levels. Because the condensing acid particles can nucleate to form particles even at very low levels of pre-existing sub-micron particles, further reduction of sub-micron solid particles will not significantly reduce plume-opacity. As an example, a unit emitting 16 ppm of vapor phase $H_2SO_4$ and 5 mg/m$^3$ of sub-micron particles is predicted to result in a plume-opacity of about 35%. An opacity of 20% can be achieved by a further reduction of sub-micron PM concentration to about 1.6 mg/m$^3$ (approximately 70%) or by a reduction of $H_2SO_4$ to about 8 ppm (a 50% reduction). For units with limited ability to further reduce PM emissions, control of $SO_3$ (and, subsequently, $H_2SO_4$) may be the only viable option for achieving plume-opacity requirements. Because essentially all the $SO_3$ is converted to $H_2SO_4$ at or below stack temperatures, Figure 2 also illustrates the impact of increases in $SO_3$ formation on plume-opacity. A unit with 1 mg/m$^3$ of sub-micron particles in the stack gases is predicted to experience doubling of plume-opacity from 5% to 10% when $H_2SO_4$ concentrations increase from 5 to 10 ppm.

Data on direct adverse effects on human health are inconsistent, but, in general, studies indicate that aqueous acidic aerosols at typical and even elevated ambient concentrations have minimal effects on symptoms and mechanical lung function in young healthy adults. However, there are studies that have shown changes in mucociliary clearance and modest bronchoconstriction in asthmatics exposed to elevated concentrations of 400 µg/m$^3$ or more. Of more concern than the effects of exposure to typical ambient levels of $SO_3$ or aqueous sulfuric acid ($H_2SO_4$) aerosols

alone are exposures to these aerosols mixed with other ambient PM constituents, including elemental carbon and metals [EPA, 1996].

In situations where $SO_3$ and $H_2SO_4$ aerosols combine with a sinking plume, the ambient concentrations near the stack can reach significantly higher levels than those normally experienced. In such cases where meteorological and operating conditions combine to form a near-stack acidic fog, damage to property and vegetation can occur if the conditions are sustained for an extended period. Anecdotal evidence of adverse health impacts such as burning eyes, sore throats, and headaches has also been reported in such cases [Hawthorne, 2001].

*Impacts on Plant Hardware*

The most common problem associated with elevated concentrations of $SO_3$ is low temperature [< 300 °F (150 °C)] corrosion. Once formed, $SO_3$ reacts easily with the moisture in combustion flue gases to produce $H_2SO_4$. Below its dew point, $H_2SO_4$ condenses and will collect in relatively low temperature areas of the flue gas path, such as the air heater, and corrode the contacted metal components. The dew point varies with $H_2SO_4$ and water concentration in the flue gas, but is typically between 200 and 300 °F (95 and 150 °C, respectively). At higher temperatures [1100-1200 °F (600-650 °C)], catalytic reactions can occur with oxidized metal surfaces to form iron trisulfates or sulfite scale. These high temperature reactions are less common than the low temperature condensation and corrosion reactions. In addition to forming corrosive $H_2SO_4$, $SO_3$ reacts to form sulfate particles (see below), especially ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate ($NH_4HSO_4$), which can lead to fouling and/or plugging of low temperature plant components, particularly the air heater. Formation of these sulfate particles also adds to the particle loading to particle control devices, especially the fine particle fraction [particulate matter (PM) smaller than 2.5 µm in aerodynamic diameter ($PM_{2.5}$)].

In some cases, modification or addition of hardware may be required to minimize corrosion or plugging. Particularly where plants have been retrofitted with wet flue gas desulfurization (FGD) systems, the reduction in flue gas temperature can result in increased $H_2SO_4$ condensation and subsequent corrosion. In such cases, the flue gas may require reheating to ensure it remains above the dew point. Reheating or increased fan power to overcome pressure drop across a plugged air heater both add to operating costs due to $SO_3$ formation [Zetlmeisl et al., 1983].

**Regulatory Overview**

There are currently no U.S. regulations that directly limit emissions of $SO_3$ and no regulations that directly limit emissions of $H_2SO_4$ aerosols from utility boilers. Other regulatory programs may, however, require $SO_3$ control as discussed below. German emission standards limit the combined $SO_2$ and $SO_3$ emission concentrations to a daily average of 50 mg/Nm$^3$ and a 30-minute average of 200 mg/Nm$^3$. There is no separate emission limit for $SO_3$ alone [Bock, 2002].

In the U.S., $SO_3$ emissions are included as part of limits on opacity and PM emissions, and $H_2SO_4$ is listed as a hazardous air pollutant (HAP) under Title III of the Clean Air Act (CAA) as amended in 1990 [CAAA, 1990]. Under Title III, electric utility generating stations are exempt from the mass emission limits of 10 tons (9.09 tonnes) per year of any single HAP or 25 tons (22.7 tonnes) per year of combined HAPs set for other industrial sources. Thus, although $H_2SO_4$ is a listed HAP and is emitted in significant quantities by coal-fired utility generating stations

[EPA, 1998], there is no regulatory requirement to control these emissions as HAPs. They must, however, be reported to EPA under the Toxics Release Inventory (TRI) requirements. The $H_2SO_4$ is typically measured and reported as equivalent $SO_3$.

EPA has defined primary PM as particles that are either emitted directly as a solid or liquid or are emitted as a vapor but condense and/or react upon cooling and dilution in the ambient air to form solid or liquid PM immediately after discharge from the stack. Secondary PM is composed of particles that form through chemical reactions in the ambient air well after dilution and condensation have occurred [EPA, 2002]. Under this definition, $SO_3$ or $H_2SO_4$ that is in vapor phase in the furnace or stack, but which either reacts to form sulfate particles or condenses to form liquid $H_2SO_4$ immediately after leaving the stack, is considered part of primary PM emissions and is therefore subject to PM emission limits.

In some states or localities, plants may be required to control $SO_3$ to maintain opacity standards. Even though opacity measurements in the stack may be within regulatory limits, the formation of a visible plume due to the presence of $SO_3$ may result in plume opacities higher than allowable levels and a need to control $SO_3$ emissions. Most states have a 20% opacity limit for stationary sources, including coal-fired utility boilers, and many also have provisions for higher opacity levels during unit start up. There are some exceptions to the 20% limit, with a few states having opacity limits of 40% and at least one (West Virginia) has a 10% opacity limit.

The formation of a detached plume occurs when in-stack opacity measurements are less than opacity measurements in the downwind plume. While in-stack opacity measurements are made using continuous emission monitors, measurements of the downwind plume opacity are covered under EPA Method 9 [40CFR60 Appendix A, 1996]. The increase in opacity from in stack measurements to downwind is often due to the condensation of vapors such as $H_2SO_4$ and can result in regulatory violations and good neighbor policy concerns.

**Formation of $SO_3$**

*Formation in the Boiler*

The sulfur in coal has inorganic and organic components. The inorganic component is predominantly pyrite ($FeS_2$), which can exist both as distinct particles (excluded) and bound in the coal matrix (included). The organic component is part of the various organic structures present in coal. The fractions of included and excluded pyrite and organic component delivered to a furnace are known to be dependent on the fineness to which the coal is ground. During the combustion of coal, virtually all of the sulfur gets oxidized to gaseous species such as $SO_2$ and $SO_3$, with $SO_2$ being the principal oxide. Although detailed chemical mechanisms for oxidation of fuel sulfur are not understood well at present, it is believed that this oxidation proceeds through rapid formation of $SO_2$, occurring on a timescale comparable to that of fuel oxidation reactions. Since $SO_2$ formation is so rapid, its concentration can be estimated using equilibrium calculations.

The primary reaction that results in $SO_3$ formation in flames is:

$$SO_2 + O + M \rightarrow SO_3 + M \qquad \text{(R1)}$$

This recombination reaction proceeds rapidly near the combustion zone in the presence of super-equilibrium concentrations of oxygen atoms (O). The consumption of $SO_3$ near flames occurs primarily via:

$$SO_3 + HO_2 \rightarrow HOSO_2 + O_2 \qquad (R2)$$

and

$$SO_3 + O \rightarrow SO_2 + O_2 \qquad (R3)$$

A few other reactions are considered to result in formation and destruction of $SO_3$ near the flame zone, but the effect of these on $SO_3$ concentrations is relatively minor. Table 1 summarizes the reactions involving $SO_3$ in the combustion zone [Alzueta et al., 2001].

To understand $SO_3$ formation, calculations were made using the sulfur chemistry described above with gas compositions and temperature-time history characteristic of a coal-fired boiler. This history is shown in Figure 3. Initial gas phase compositions are assumed to result from complete combustion (with 10 and 30% excess air) of a Montana subbituminous and a Western Kentucky bituminous coal. The subbituminous coal is composed of 53.26 % (by weight) carbon, 3.35% hydrogen, 0.87% nitrogen, 0.78% sulfur, 9.34% ash, 21.23% water, and 11.16% oxygen. The bituminous coal contains 69.79 % carbon, 4.79% hydrogen, 1.34% nitrogen, 2.95% sulfur, 7.47% ash, 5.0% water, and 8.65% oxygen. The initial compositions resulting from complete combustion of above coals are then equilibrated at 1647 °C (1900 K) to provide the input composition for the chemical kinetic calculations based on the above sulfur chemistry. Note that the $H_2$-$O_2$-CO subset of the hydrocarbon mechanism given in Warnatz et al. (1996) is used in these calculations. This subset includes 25 reactions involving 11 species.

Figures 4a and 4b plot $SO_3$ mole fraction and the ratio $SO_3$ mole fraction/$SO_2$ mole fraction versus time, respectively. Since Reaction R1 is exothermic, little $SO_3$ is formed initially at high temperatures in the furnace. As the flue gas cools, $SO_3$ is produced, and the rate of production is high in the convective region of the boiler (see Figures 3 and 4a). $SO_3$ production via gas-phase sulfur kinetics is complete before the flue gas enters the economizer. The results also reflect that $SO_3$ production increases with coal sulfur content and furnace excess air level. This is because an increase in sulfur content of coal and/or furnace excess air level results in a corresponding increase in the concentration of $SO_2$ and/or oxygen atom (O), which, in turn, results in greater production of $SO_3$ via reaction R1. Finally, Figure 4b reflects that $SO_2$ conversion rate (i.e., $SO_3/SO_2$ molar ratio) for the modeled coals ranges between 0.1 and 0.65%, approximately, and is relatively independent of coal type at a specific excess air level. Since boilers are operated with between 10 and 30% excess air, a 0.65% conversion of coal sulfur to $SO_3$ should provide a conservative estimate of $SO_3$ production in the furnace.

In addition to the $SO_3$ formation in the furnace discussed above, additional formation takes place in the temperature range of 1100-800 °F (593-427 °C) found in the economizer region of the boiler. This formation results from oxidation of $SO_2$ via molecular oxygen ($O_2$) [Hardman et al., 1998] catalyzed by iron oxides present in both ash and tube surfaces. This oxidation mechanism

depends on several operating and design parameters including $SO_2$ concentration, ash content and composition, convective pass surface area, gas and tube surface temperature distributions, and excess air level. Since the impact of these parameters depends on site-specific factors (e.g., cleanliness of tube surfaces), it is difficult to characterize the extent of $SO_3$ formation due to catalytic oxidation of $SO_2$. A laboratory study found that the oxidation rate of $SO_2$ in the presence of fly ash was between 10 and 30% [Marier et al., 1974] and increased essentially linearly with the iron oxide content of the ash. These oxidation rates are substantial higher than those found in coal fired boilers, for which data suggests furnace/economizer conversion to be approximately 0.8 to 1.6% for bituminous and 0.05 to 0.1% for subbituminous coals [Monroe, 2001]. The above laboratory study results indicate that temperatures and residence times greater than, and carbon ash contents lower than, those typically found in coal-fired utility boilers are required to achieve high oxidation rates.

*Formation of $SO_3$ in SCR Reactors*

The SCR technology is increasingly being used at power plants to control emissions of $NO_x$. In the SCR process, ammonia ($NH_3$) is injected into the flue gas within a temperature range of about 600 to 750 °F (315 to 400 °C), upstream of a catalyst. Subsequently, as the flue gas contacts the SCR catalyst, $NO_X$, which predominantly is NO in combustion devices, is chemically reduced to molecular nitrogen ($N_2$). In the most commonly used SCR process layout, known as hot-side SCR, the catalyst is located between the economizer and the air preheater (APH).

It is well known that the catalyst used in the SCR technology oxidizes a small fraction of $SO_2$ in the flue gas to $SO_3$:

$$SO_2 + \tfrac{1}{2} O_2 \rightarrow SO_3 \qquad \text{(R4)}$$

The extent of this oxidation depends on the catalyst formulation and SCR operating conditions. Generally, this oxidation can range from 0.25% to 0.5% of $SO_2$ per layer of catalyst in bituminous and 0.75 to 1.25% per layer in low-sulfur subbituminous coal applications. Also, in general, 2-3 layers of catalyst are used in SCR applications. To examine what this oxidation means, consider an SCR application using two layers of catalyst, each with an $SO_2$ oxidation guarantee of 0.25%. Also assume that the concentrations of $SO_2$ and $SO_3$ in the flue gas at the inlet of the SCR reactor are 2000 ppm and 20 ppm, respectively. Then based on oxidation across the first catalyst layer, the concentrations of $SO_2$ and $SO_3$ at the beginning of the second layer will be 0.9975x2000 = 1995 ppm and 2000-1995 + 20 = 25 ppm, respectively. Similarly, the concentrations of $SO_2$ and $SO_3$ at the end of the second layer will be 0.9975x1995 = 1990 ppm and 1995-1990+25 = 30 ppm, respectively. Thus, the $SO_3$ loading in the flue gas at the exit of the SCR reactor will be 50% more than that at the inlet. This example illustrates that level of oxidation across the catalyst can have a large impact on $SO_3$ concentration.

In general, for a given catalyst material experiencing same flue gas conditions, the oxidation rate of $SO_2$ to $SO_3$ (or conversion rate) is inversely proportional to area velocity (AV), which is simply the ratio of flue gas volumetric flow rate to geometric catalyst surface area. This implies that the conversion rate is proportional to catalyst volume (and hence geometric surface area) and gas residence time in the catalyst. Thus, the conversion rate, $\kappa$, can be expressed as:

$$\kappa = K/AV \quad (1)$$

where the constant of proportionality, K, is a function of catalyst material and design as well as flue gas properties [Gutberlet et al., 1999], i.e.,

$$K = f(\text{catalyst material, catalyst design, flue gas properties}) \quad (2)$$

Svachula et al. (1993) have conducted a systematic study of oxidation of $SO_2$ to $SO_3$ over honeycomb SCR catalysts. Their findings are as follows:

(1) the conversion rate depends primarily on the vanadium content of the catalyst and, therefore, can be controlled by adjusting this content;
(2) the oxidation reaction is considerably slower than diffusion of $SO_2$ within the pores of the catalyst. Therefore, the entire volume of the catalyst is active in oxidation of $SO_2$ to $SO_3$ in contrast to reduction of $NO_x$ to $N_2$, which, being diffusion-limited, occurs mainly at the catalyst surface. The rate of oxidation is linearly proportional to catalyst wall thickness. Accordingly, reducing the wall thickness should not affect $NO_x$ reduction, but should reduce $SO_2$ to $SO_3$ conversion;
(3) the reaction rate is of variable order in $SO_2$ concentration, increases with temperature, is independent of concentrations of oxygen and water in practical applications, is strongly inhibited by $NH_3$, and is slightly enhanced by $NO_x$.

**$SO_3$ Depletion or Conversion to $H_2SO_4$**

*Processes in Air Preheaters*

Utility boilers use APHs to transfer heat from hot flue gas exiting the economizer to combustion air flowing into the boiler. These APHs are available in rotary regenerative and tubular designs, with the former used more widely. Typically the flue gas temperature at the APH inlet is between 600 and 700 °F (316 and 371 °C) and about 300 °F (149 °C) at the exit. $SO_3$ is hygroscopic and, therefore, absorbs vapor-phase moisture at temperatures above its dew point to form $H_2SO_4$ vapor [Hardman et al., 1998]. This process occurs in the APH. The extent of conversion of $SO_3$ to $H_2SO_4$ depends on the temperature distribution in the APH and flue gas moisture content. However, virtually all $SO_3$ converts to $H_2SO_4$ at temperatures of 400 °F or less. If local metal temperatures in the APH flow passages drop below the acid dew point (ADP), some $H_2SO_4$ condenses on these surfaces as liquid droplets (aerosol). This rate of condensation is dependent on the wall temperature and $H_2SO_4$ concentration in the flue gas.

In a regenerative APH, where flow passages are periodically exposed to hot flue gas and relatively cold incoming combustion air, evaporation of condensed $H_2SO_4$ occurs on exposure to air. The rate of this evaporation is dependent on moisture content of air and metal surface temperature of the APH flow passage [Levy, 1998; Sarunac and Levy, 1999].

Devito and Oda [1998] have reported that, based on the results of an extensive field test program, approximately 40% of the flue gas $SO_3$ present at the regenerative APH inlet is removed in the APH by the condensation-evaporation mechanism discussed above. The tubular APH design does not have surfaces that are periodically exposed to combustion air; except for small leakages

in welds and seal, no mixing of the flue gas and combustion occurs. Therefore, the resultant $H_2SO_4$ formed is not removed by evaporation into the combustion air and passes directly out of the APH. Yilmaz et al. (1995) have modeled the acid condensation phenomenon in tubular APHs.

In addition to the condensation-evaporation of $SO_3$ discussed above, an additional conversion process takes place in boilers equipped with SCR. In such a case, $NH_3$ is injected as a reagent in the SCR process. A minor fraction, 2 to 5 ppmv, of injected ammonia slips past the SCR catalyst and does not react with $NO_x$. This fraction of $NH_3$, known as $NH_3$ slip, reacts with $SO_3$ downstream of the SCR reactor and forms ammonium sulfate and ammonium bisulfate salts and, thereby, results in removal of $SO_3$ from the flue gas. This salt formation can be detrimental to the APH performance if APH passages become plugged and pressure loss across the APH results in forcing off-line washing. The amount and type of ammonia salt formed will depend on the amount of $NH_3$ slip; based on typical concentrations of $SO_3$ and $H_2O$ in flue gas, the amount of $NH_3$ slip is the limiting factor in salt-formation reactions.

*Localized Condensation of $H_2SO_4$ in the Duct Between APH and PM Control*
Condensation of $H_2SO_4$ can also take place in the duct between the APH and the PM control device. For example, due to the rotating heat transfer element employed in the regenerative APH, gas flow stratification across the flow cross-section downstream of the boiler is enhanced in the APH. As a result, strong transverse variations in gas temperature and $H_2SO_4$ vapor concentration can exist in the gas leaving the APH. These variations can lead to localized condensation of $H_2SO_4$. Based on operating conditions, localized condensation can also occur in units using tubular APHs. For a given combination of flue gas $H_2SO_4$ concentration, dew point and, moisture content, Figure 1 can be used to determine if condensation is occurring.

*Flyash Adsorption and Removal of $H_2SO_4$ in PM Control Equipment*
In addition to the processes described above, some $H_2SO_4$ gets adsorbed on fly ash in the APH and downstream equipment. The rate of this adsorption depends on the temperature of the flue gas; concentration of $H_2SO_4$; and fly ash properties, in particular, alkalinity. The adsorption may increase rapidly as the flue gas reaches the cold end of the APH and may continue in the duct between the APH and the PM control equipment. The adsorbed $H_2SO_4$ gets removed with the fly ash in the PM control device [electrostatic precipitator (ESP) or baghouse].

The firing of subbituminous coals, which generally have sulfur contents on the order of 0.5%, results in fly ash with a relatively high amount of alkali (20-30% by weight). Such alkaline ash adsorbs virtually all $H_2SO_4$ in the flue gas. In such cases, $SO_3$ injection is required for improving electrostatic precipitator (ESP) performance. In contrast, based on fly ash properties and temperature, the majority of $SO_3$ in flue gas of a bituminous coal-fired boiler may, or may not, be adsorbed in flyash [Gutberlet et al., 1999]. Finally, hot-side ESPs operate at high enough temperatures where little adsorption of $H_2SO_4$ occurs.

As mentioned above, adsorption of $H_2SO_4$ on fly ash depends on alkalinity of fly ash and concentration of $H_2SO_4$. Figure 5 illustrates the general adsorption characteristics of fly ash as a function of the molar ratio of alkali content of fly ash and $SO_3$ concentration at the inlet of the APH. The alkali content of fly ash is defined as the molar sum of magnesium oxide (MgO) and

calcium oxide (CaO) in the ash. This figure represents a correlation of data from BBP field-testing programs concerning $SO_3$ production and capture in flue gas systems.

*Aerosol Formation in Wet Flue Gas Desulfurization Systems*
As the $H_2SO_4$ vapor containing flue gas passes through a wet flue gas desulfurization (FGD) system, it is rapidly cooled below the acid dew point. Since the rate of this cooling is greater than the rate of absorption of $H_2SO_4$ vapor in the scrubber solution, the dew point crossover results in $H_2SO_4$ mist with sub-micron droplets [Gutberlet et al., 1999; Blythe et al., 2001b]. Generally, larger droplets in the mist can be removed in the scrubber, but the sub-micron droplets are not removed and are emitted from the stack. This explains why wet FGD systems are relatively inefficient in removing $SO_3/H_2SO_4$. In general, about 50% of the $H_2SO_4$ entering the scrubber may be removed in the scrubber.

**Measurement of $SO_3$**
The measurement techniques for $SO_3$ and $H_2SO_4$ have recently been under review for accuracy and improvement for Toxic Release Inventory (TRI) reporting. The Controlled Condensation System (CCS) has been used since the 1960's for the measurement of $SO_3$ and $H_2SO_4$ in flue gas streams [Lisle and Sensenbaugh, 1965; Dismukes, 1975]. Recently a review and verification project has been undertaken by Electric Power Research Institute (EPRI) to qualify the CCS method and compare field data to available prediction methods used to estimate $SO_3$ emissions for TRI reporting [Blythe et al., 2001a]. The EPRI project compared laboratory data to field test data for a variety of coals with a range of sulfur and fly ash chemical compositions. The study further investigated the $SO_3$ removal rates and efficiencies of the plant equipment used for field verification.

The general arrangement of the CCS and thimble holder is shown in Figures 6 and 7, respectively. The measurement system consists of quartz lined heated probe which draws gas through a quartz thimble for the removal of particulate matter. The probe and thimble are heated to avoid condensation of $SO_3$ vapor in the gas sample. The gases enter a temperature-controlled condenser where the $SO_3$ is condensed on the wall and collected and measured after the sample run via a deionized water rinse. The EPRI project has concluded that alkaline ash will produce a bias in the $SO_3$ measurement. The bias is a result of $SO_3$ removal in the thimble holder by the alkaline ash collected on the quartz thimble. This bias is seen as significant for low sulfur, high alkaline ash fuels (PRB coals). The CCS was found to have a bias of 20 to 25% low readings for high sulfur, acidic ash fuels and greater than 40% for PRB coals. A possible solution to the bias is utilized in Europe [Gutberlet 2002]. The test method uses a system similar to the CCS; however, the quartz thimble is replaced with a small tubular ESP. The tubular ESP removes the ash to the sidewalls away from the gas stream; in contrast the quartz thimble filters the flue gas through the collected ash. Furthermore, the European system can distinguish between gaseous and aerosol $SO_3$ using deionized water procedures of various collection plates. The European $SO_3$ method system has been used extensively in the U.S. on a variety of coals with repeatable and reliable results.

**Mitigation of $SO_3$ Emissions**
The mitigation of $SO_3$ has been an active area of research for many years [Reese et al., 1965]. This research has resulted in the development, refinement, and implementation of different

techniques and methods for the successful mitigation of $SO_3$ in the flue gases of fossil fuel fired boilers. Recently, a guide that summarizes $SO_3$ mitigation options and their respective success in either full scale or pilot testing has been written [Peterson et al., 1994]. Since the guide was issued, the installation of full-scale SCR units has made the need for mitigation greater. Consequently, the number of full-scale tests and operating installations of $SO_3$ mitigation equipment has increased.

*Alkali Addition into Furnace*

The injection of alkali in the flue gas stream has been a method of $SO_3$ mitigation for almost 30 years [Reese et al., 1965]. The location in the flue gas stream and delivery method of the alkali has been studied and tested depending on operating and site conditions.

The addition of alkali into the furnace has recently been proven effective at the full scale [Gutberlet et al., 1999; and Blythe et al., 2001b]. However, the method of delivery and effectiveness of the alkali used varies from site to site depending on specific conditions. The addition of limestone to coal prior to pulverization for the control of SCR catalyst arsenic poisoning has been shown to be an effective method of furnace $SO_3$ control. Recent commissioning data [Hutcheson et al., 2002] has shown at least a 50% reduction in furnace $SO_3$ from limestone addition. The injection of alkaline sorbents (calcium and magnesium based slurries) has been shown to be effective at controlling $SO_3$ emissions of the furnace [Blythe el al., 2001b]. The slurry injection method has successfully obtained $SO_3$ furnace conversion reductions of 40 to 80% but has been found to be sensitive to injection location and elevation. The effects of the MgO sorbent slurries on SCR catalyst activity are currently under investigation. To date, no studies have measured the potential benefit of SCR catalyst arsenic poisoning control by MgO sorbent injection. The addition or injection of alkaline in the furnace does not influence the conversion rate of the SCR catalyst.

*Alkali injection After Furnace*

The injection of other alkaline materials after the furnace/economizer exit has been used for the control of $SO_3$ for both APH corrosion and stack emissions [Peterson, et al. 1994]. The primary sorbents used are compounds such as hydrated lime [$Ca(OH)_2$], limestone ($CaCO_3$), MgO, and sodium carbonate ($NaHCO_3$). The selection of a sorbent for a given site will depend on economic factor such as availability and required $SO_3$ removal rates. Alkali injection has successfully removed between 40 and 90% of the $SO_3$ in the flue as various plants depending on the injected material and injection rate [Peterson, et al. 1994]. The sorbents are introduced into the flue as either a dry powder or mixed with water to form slurry prior to injection. The location in the flue gas stream varies. Plants with APH cold-end corrosion problems may elect to inject the sorbent before the APH; however, adequate APH cleaning equipment is required with this configuration. In general, for $SO_3$ control the common injection location is between the APH and the ESP. The injection of sorbent before the ESP must consider the effect on particulate control. The ESP will have higher inlet mass loading, and the fly ash will have different resistivity characteristics. It has been reported that dry injection of hydrated lime has resulted in strong sparking and lower operating currents in the ESP during pilot scale testing [Peterson, et al. 1994]. The injection of sodium materials can result in landfill problems due to the leaching of the water soluble sodium salts.

*Ammonia Injection Before ESP*
The injection of ammonia after the APH and before the ESP has been shown to be <90% effective in the removal on $SO_3$ in full-scale application [Peterson et al., 1994]. This method of mitigation results in the formation of ammonium sulfate and ammonium bisulfate salts in the ESP, depending on the $NH_3$ and $SO_3$ concentration ratios. The formation of ammonium bisulfate is expected when $NH_3$ to $SO_3$ molar ratios are less than 1.0; this formation tends to decrease the ESP particle loading due to fly ash agglomeration. Ammonia injection prior to the ESP is used for fly ash conditioning to increase ESP performance due to the agglomeration effects. With $NH_3$ to $SO_3$ molar ratios between 1.0 and 2.0, increased formation of ammonium sulfate is expected, with an increase in the particle loading of the ESP. The injection of ammonia results in the adsorption of ammonia by the fly ash. Since the fly ash will contain most of the injected ammonia, the concentration may exceed acceptance limits for ash salability or disposal. Additional treatment of fly ash holding ponds and basins may be required if large amounts (~30 ppmv) of $SO_3$ are being removed. High concentrations of atmospheric ammonia vapor can result when the fly ash is wetted. Generally, these concentrations are not a health concern, but may be irritating to operators. The use of ammonia for $SO_3$ mitigation is practical on units equipped with SCRs, since ammonia is used as the reagent and is readily available on site.

*Fuel Switching and Blending*
The firing of subbituminous coals typically results in low $SO_3$ formation and emission rates. However, equipment and fuel cost factors often make such a change impossible. Many boiler systems do not have the capacity and the equipment to accommodate the firing of subbituminous coal without major modifications that make fuel switch economically unacceptable. Coal availability and costs can also constrain fuel switching. One possible solution is the blending of bituminous and subbituminous coals to create a blend that has fuel and ash characteristics favorable for $SO_3$ emissions. This strategy is currently used for the control of $SO_2$ emissions. When subbituminous coals are blended with bituminous coals, the overall sulfur content of the fuel is reduced, resulting in a reduction of the $SO_2$ concentration in the flue gas as well as the conversion of $SO_2$ to $SO_3$ in the furnace and SCR and, thereby, resulting in an overall reduction in $SO_3$. Also, the subbituminous coal ash contains large percentages of alkaline materials that further assist in the capture of $SO_3$ in the APH and ESP.

*Wet Electrostatic Precipitators*
Similar to dry electrostatic precipitators (ESPs), wet electrostatic precipitators (WESPs) operate in a three-step process involving: (1) charging of the entering particles; (2) collection of the particles on the surface of an oppositely charged surface; and (3) cleaning the collection surface. Both technologies employ separate charging and collection systems. However, the collecting surface in WESPs is cleaned with a liquid, in contrast to mechanically in dry ESPs. Consequently, the two technologies differ in the nature of particles that can be removed, the overall efficiency of removal, and the design and maintenance parameters [Altman et al., 2001a]. While dry ESPs are typically limited to power levels of 100-500 watts per 1,000 cfm of flue gas, WESPs can operate with power levels as high as 2,000 watts per 1,000 cfm. Due to wet cleansing of the collection system, particulate matter does not accumulate in the collection electrodes; this mitigates particle re-entrainment. Based on these factors, WESPs can collect sub-micron particles and acid mist very efficiently. WESPs can be configured for vertical or

horizontal gas flows in tubular or plate designs. Tubular designs offer smaller footprint and, in general, are more efficient than the plate type.

WESPs can be easily integrated with a wet scrubber. In fact, integration of the WESP *within* the wet scrubber is a design option with many attractive features including [Bielawski, 2001] a compact footprint; the ability to integrate the handling of the wash water and solids from the WESP with scrubber slurry, avoiding the need for separate tank and blowdown system; and the ability to collect the fine sulfuric acid mist, which typically escapes the scrubber due to its very small droplet size.

In 1986, the first commercial WESP application on a U.S. power plant took place when AES Deepwater, a 155 MW cogeneration plant firing petroleum coke as the primary fuel, was equipped with a WESP. With the WESP in operation, the plume opacity at the plant is generally 10% or less [Kumar and Mansour, 2002].

Recently, an up-flow tubular design WESP has been retrofit Northern States Power Company's Sherco Station in a wet scrubber/WESP configuration. Two more power plant applications are underway presently: 1) 5,000 cfm slipstream at Bruce Mansfield Station; and 2) a plate type WESP for integration with Powerspan's ECO technology to be demonstrated at First Energy's R.E. Burger plant.

Tests at the Sherco Station (WESP retrofit to the outlet section of the wet scrubber) allowed the scrubber to maintain a 70 % $SO_2$ reduction while keeping particulate emissions at 0.01 lb/$10^6$ Btu and opacity under 10%. Full conversion of all scrubber modules at the plant with WESPs is now underway [Altman et al., 2001a]. The WESP at the Mansfield Station is achieving greater than 95% removal of $SO_3$ and $PM_{2.5}$ and stack flow with near-zero opacity [Reynolds, 2002].

*Changing the operation of APH*

Increasing the heat transfer (or the cooling of the flue gas) in the APH would appear to be a potentially viable strategy for removing some of the $SO_3/H_2SO_4$ in the APH. This, in turn, would lead to increased condensation of $H_2SO_4$ in the APH and also to improved plant efficiency. However, the dew point at the APH outlet is around 230 °F (110 °C), thereby limiting the $SO_3$ removal to about 90% [Gutberlet et al., 1999]. On the other hand, potential for corrosion in the APH and downstream duct would increase with increased $H_2SO_4$ condensation. Consequently, more frequent soot blowing may be required to control this corrosion. These factors would need to be considered while deciding to change the APH operation to mitigate $SO_3$ emissions. Data reflects that about 25% increase in $H_2SO_4$ condensation may be possible by lowering the flue gas temperature at the APH exit by about 40 °F (22 °C).

**Summary**

Formation and emissions of $SO_3$ can lead to serious problems for plant operation and for achieving environmental compliance. The formation of $SO_3$ is complex, depending upon fuel, operating parameters, and plant configuration, and understanding the parameters leading to excessive generation of $SO_3$ and subsequent formation of $H_2SO_4$ can minimize their presence and adverse impacts. Elevated $SO_3$ concentrations can lead to corrosion, the formation of sulfite

scale, fouling and plugging of low temperature plant components, and can add to the particle loading to control equipment. In some cases, elevated $SO_3$ concentrations can lead to the formation of visible plumes at the stack exit or shortly downstream of the stack, resulting in noncompliance with local regulations. $SO_3$ can be formed in the boiler during the combustion of sulfur-bearing fuels, or downstream, particularly in SCR reactors. $SO_3$ that forms $H_2SO_4$ can condense on low temperature components or, in some cases be absorbed by fly ash. Absorption by fly ash is much greater for the high alkaline ashes present in subbituminous coals, and, in some cases, injection of $SO_3$ may be needed to improve ESP performance. $SO_3$ has traditionally been measured using extractive controlled condensation methods, but, more recently, methods are being developed and applied that provide semi-continuous measurements or predictions.

$SO_3$ formation can be mitigated using a variety of methods. Injection of alkali materials into the furnace, either with the fuel or in slurry form, have resulted in reductions of up to 80%. Post-furnace injection of alkali materials can achieve up to 90% reductions, but can increase particle loadings and ash resistivity characteristics, and potentially result in landfill problems due to leaching of water soluble salts. Ammonia injection can also reduce $SO_3$ by roughly 90%, again with the disadvantage of increasing particle loading to the downstream collection systems. In plants with adequate operational and equipment flexibility, fuel switching can be used to reduce formation and emissions of $SO_3$, although coal costs and availability and plant design may limit the use of this approach. Wet ESPs are also an option for control of $SO_3$ and subsequent visible plumes, and a variety of designs have been successfully demonstrated for collection of acid mists and opacity control.

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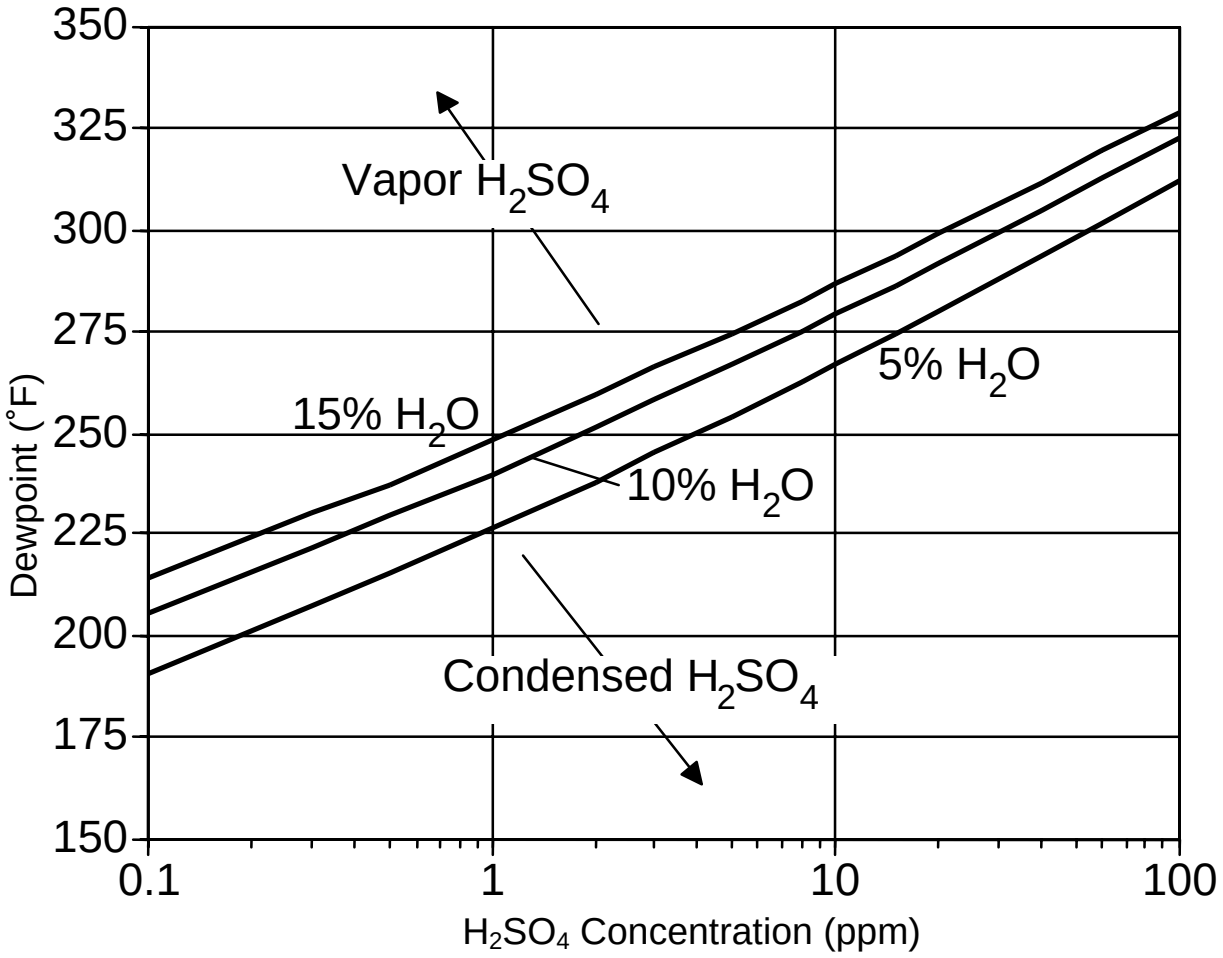


Figure 1. Dew point of $H_2SO_4$ as a function of $H_2SO_4$ concentration for different water vapor concentrations (from Verhoff and Banchero 1974).

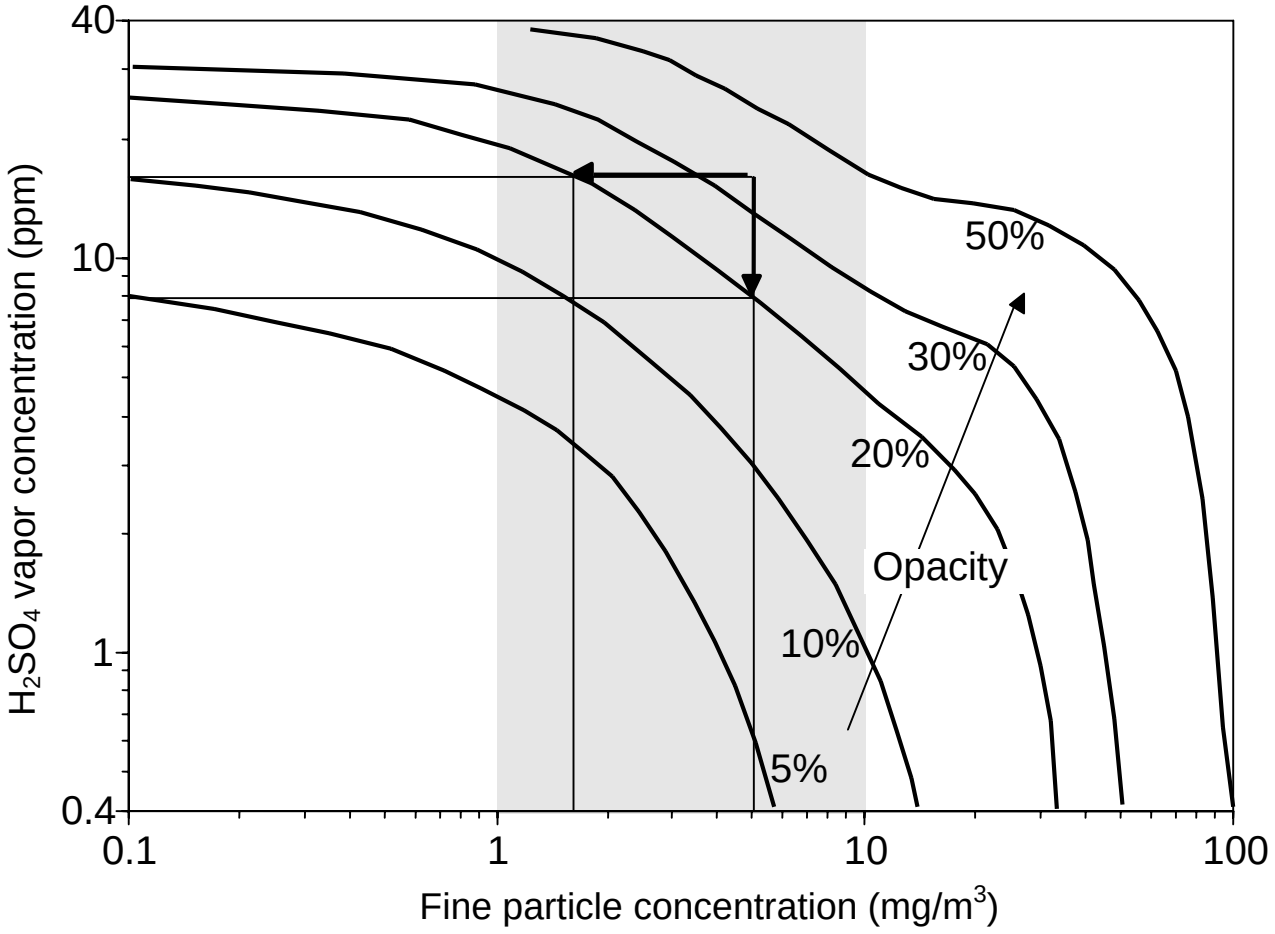


Figure 2. Iso-opacity plot calculated for a bimodal distribution of coarse and sub-micron particles. The sub-micron particle mode is at 0.15 µm diameter (from Damle et al., 1987). The gray area represents typical sub-micron mass concentrations in the stack of a coal-fired utility boiler [Markowski et al., 1980].

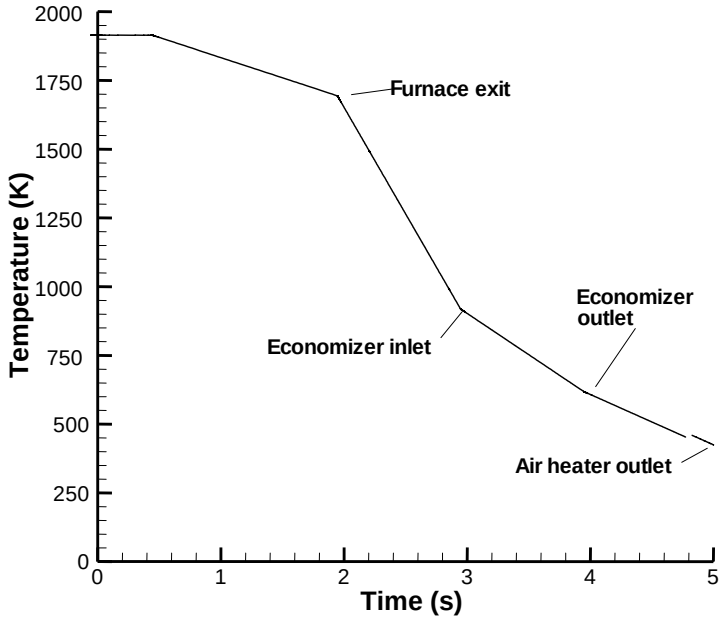


Figure 3. Temperature-time history for a coal-fired power plant (from Senior et al., 1999).

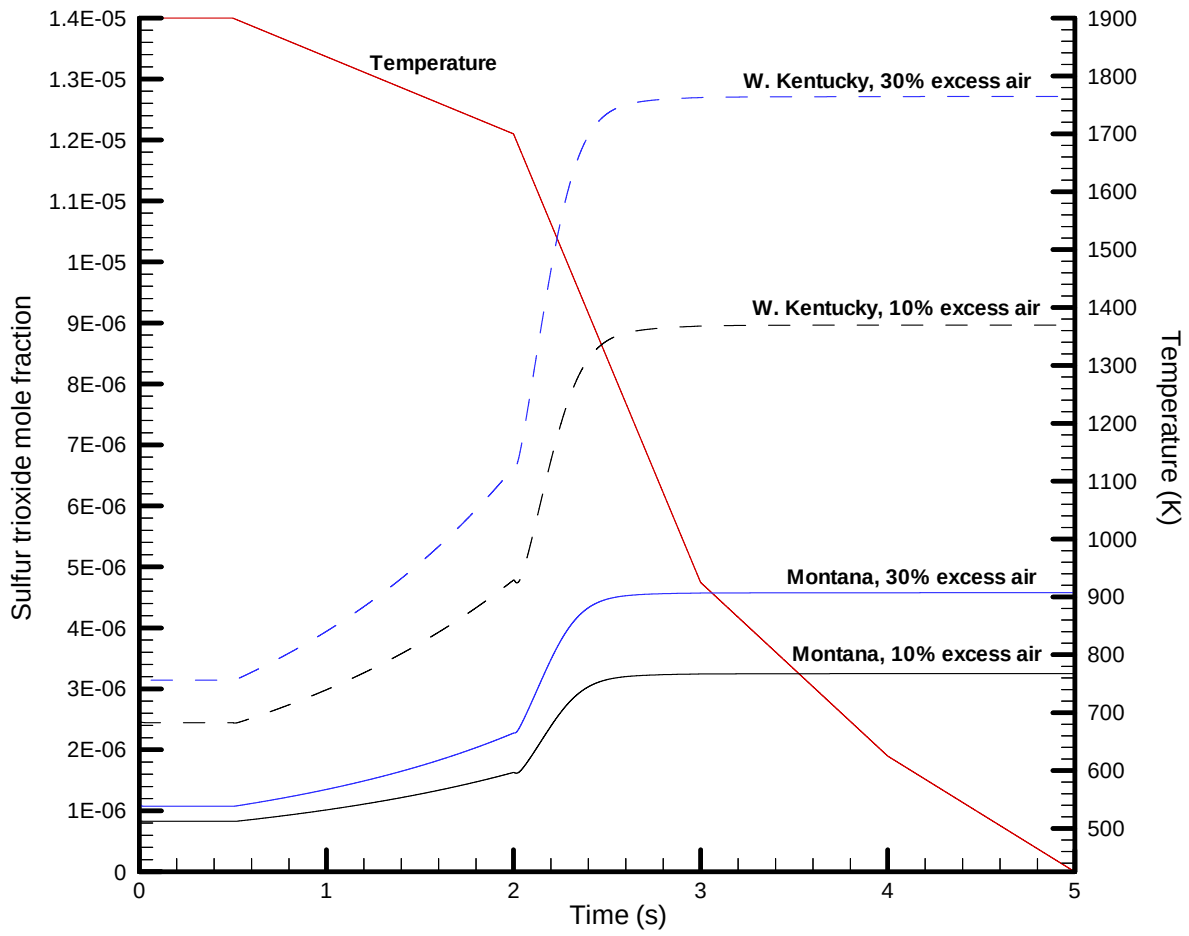


Figure 4a. $SO_3$ produced during coal combustion.

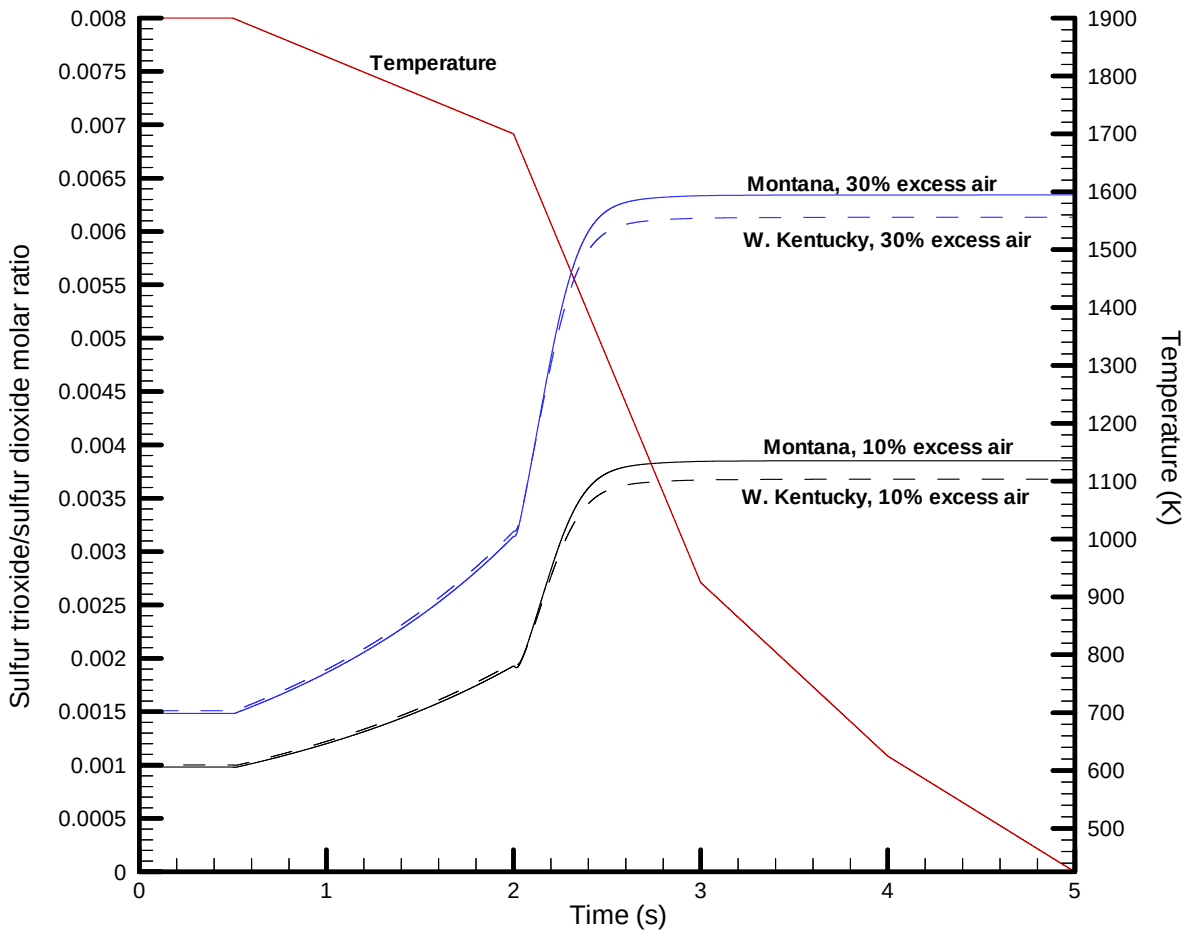


Figure 4b. $SO_2$ conversion during coal combustion.

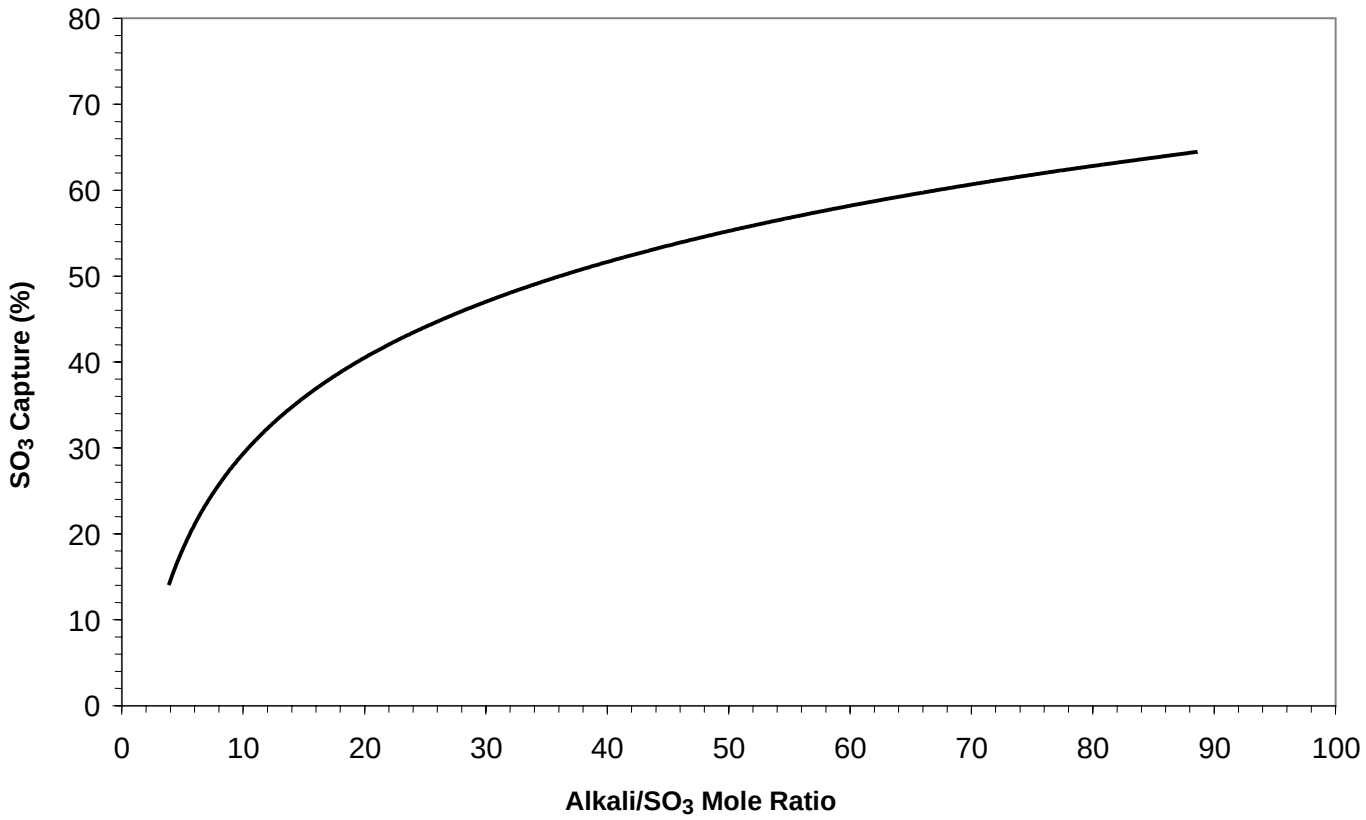


Figure 5. Fly ash $SO_3$ capture rate down stream of furnace.

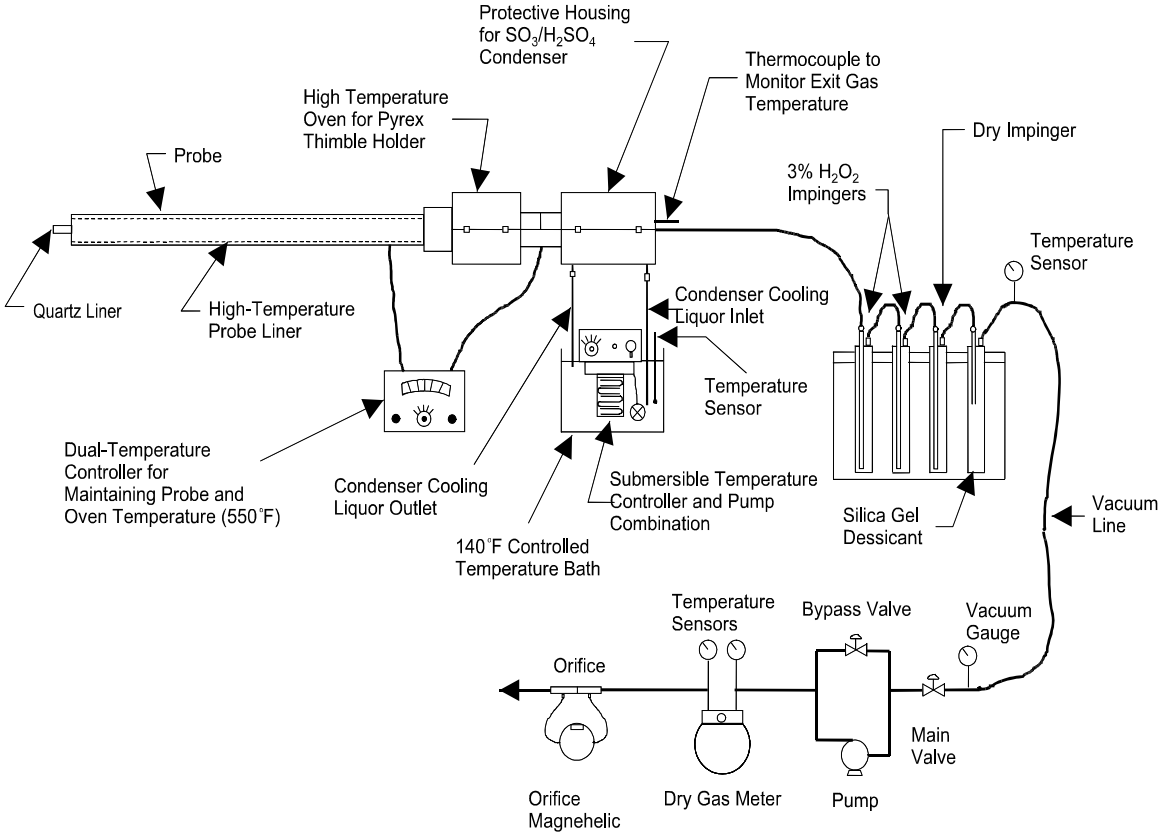


Figure 6. Controlled condensation system (CCS) sampling train.

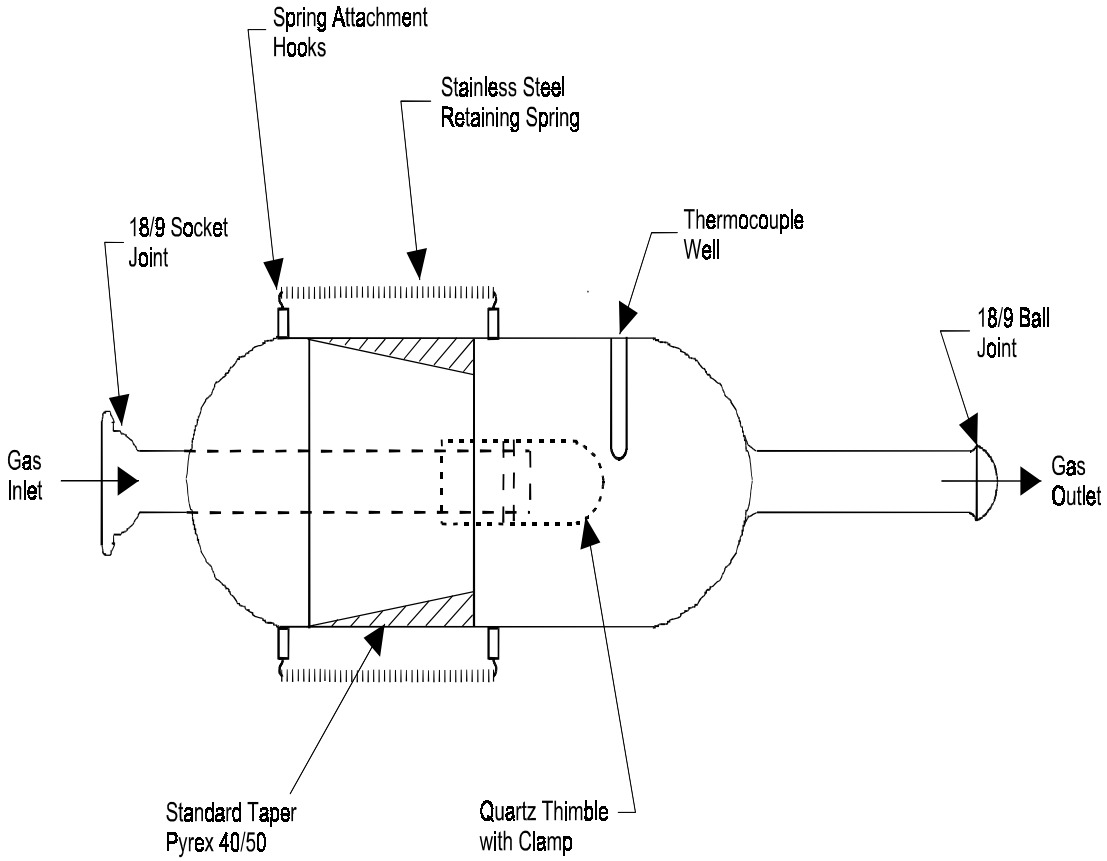


Figure 7. CCS thimble holder.

**Table 1.** The reactions involving $SO_3$ in the combustion zone. The rate constants are listed in the form $k = AT^{\beta} \exp(-E_A/RT)$ with units in mol-cm-s.

| **Reaction** | **A** | $\beta$ | $\mathbf{E_A/R}$ |
|---|---|---|---|
| $SO_3 + H = HOSO + O$ | 2.5e05 | 2.92 | 25300 |
| $SO_3 + O = SO_2 + O_2$ | 2.0e12 | 0.00 | 10000 |
| $SO_3 + SO = SO_2 + SO_2$ | 1.0e12 | 0.00 | 5000 |
| $SO_2 + O + M = SO_3 + M$ | 9.2e10 | 0.00 | 1200 |
| $SO_2 + OH = SO_3 + H$ | 4.9e02 | 2.69 | 12000 |
| $HOSO_2 = SO_3 + H$ | 1.4e18 | -2.91 | 27600 |
| $HOSO_2 + O = SO_3 + OH$ | 5.0e12 | 0.00 | 0 |
| $HOSO_2 + OH = SO_3 + H_2O$ | 1.0e12 | 0.00 | 0 |
| $HOSO_2 + O_2 = SO_3 + HO_2$ | 7.8e11 | 0.00 | 330 |

# The Past, Present and Future of Wet Electrostatic Precipitators in Power Plant Applications

**Paper #207**

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## BACKGROUND

Wet electrostatic precipitators (WESPs) have been commercially available since their first introduction by F. G. Cottrell in 1907. However, most of their use has been with small, industrial-type settings as opposed to electrical utility power plants. In the past 20 years, this technology has been applied periodically to electric power plant sources.

In electric utility plants firing sulfur-bearing fuel, wet flue gas desulfurization (WFGD) and, in the past decade, selective catalytic reduction (SCR) technologies have been added to control sulfur dioxide and nitrogen oxides emissions. The recent start-ups of new SCR systems on coal-fired power plants have demonstrated an increase of sulfuric acid emissions due to the oxidation of a portion of $SO_2$ across the SCR catalysts.[1] Although the control of sulfuric acid mist from electric utility sources has typically not been regulated, concern and questions regarding these emissions are now being observed.

The combustion of petroleum coke or Orimulsion™ with relatively higher concentrations of vanadium (a catalyst for the oxidation of $SO_2$ produced in combustion to $SO_3$) produces high levels of sulfuric acid emissions, in some cases as high as at power plants firing high sulfur coal.[2]

In cases where the wet FGD technology is utilized in conjunction with SCRs on high sulfur coals or with high vanadium petroleum fuels, the condensed sulfuric acid component in the flue gas can exceed 20 ppmvd @ 3% $O_2$. This causes a pronounced stack opacity because of the inherent light scattering properties of the sub-micron particulates.[3] Acid mist concentrations as low as 5 to 10 ppmvd have caused visible plume problems.

This paper will discuss the past application of WESP technology, recent experiences that pertain to the electric utility industry, and economic analyses of WESP application to address potential and future utility needs. The analyses compare the WESP to the alternative approach of sorbent injection to control acid mist emissions.

## PAST WESP EXPERIENCE

As stated above, WESPs have been serving the needs of metallurgical industry and many other applications for nearly 100 years, to control sulfuric acid and particulates. More than 1000 WESPs are in worldwide commercial operation today.[4] There are several configurations of WESP designs now proven in commercial practice. WESPs are made of tubular and parallel-plate type collecting electrodes. While the tubular WESPs will have only vertical gas flow orientation (upflow or downflow), the plate type designs can have either horizontal gas flow or vertical gas flow orientation.

Materials of construction have long been a major issue in WESP design for metallurgical applications. In copper roasters, for example, the $SO_2$ concentrations in off-gases often exceed 10% because of high pyritic content in the ore. Environmental regulations that reduced $SO_2$ emissions from these sources led to the commercialization of converting this rich, $SO_2$ laden gas stream into a usable resource – sulfuric acid. Ironically, the WESP technology also protected the process' vanadium oxidation catalyst from being "poisoned" and plugged by reducing the particulates and $SO_3$ prior to entering the acid plant. The WESPs became the workhorses for the industry in collecting sulfuric acid mist. WESPs also removed trace elements, such as arsenic, to enhance the quality of sulfuric acid made in the acid plant.

In the 1940s, the typical WESP design for acid mist control commonly used corrosion-resistant lead collection surfaces (both plate and tubes), lead-lined mild steel high voltage systems, and casings comprised of skeleton steel structures with lead burned over the steel surfaces for protection from the acid gas stream. Due to the structural weakness of the lead and the operating pressures of downstream acid plants, leaks would occur and soon the skeleton steel structure underwent corrosive attack and failed. Additionally, corrosion-resistant lead materials were shown to be susceptible to mechanical failure when used at operational temperatures above approximately 150°F. Eventually, the casing design evolved to alternatives such as fiberglass reinforced plastic to house the lead and lead-covered internals. This new design improved the life cycle of the WESPs and also minimized the need for highly skilled lead burner craftsmen. During this same timeframe, some manufactures started using plastic and FRP collecting electrodes to further minimize the lead content of their designs. In the 1970s some manufacturers began using specialty stainless for any lead-covered components that remained in their designs. The main driving forces behind these evolutions were problems associated with the use of lead, including the specialized construction and maintenance labor required, reliability and maintenance/repair costs, and the ever growing concern over lead toxicity.

There has been a recent report of a toxics release at a metallurgical plant as a result of a fire within a WESP that used polypropylene collecting tubes and FRP casing. This type of experience has raised concern in other plants using plastic WESP components.

Therefore, given the above, it is anticipated that electric utility power plants may understandably show a reluctance to use lead or plastic components in their WESPs.

During the 1970s and 1980s, the successful use of alloy in wet FGD inlet sections and outlet flues provided sufficient confidence in the further use and applications of alloys. Today, alloy steels including 317, 6% molybdenum and C-276 grades are being used routinely in wet FGD systems.

What has emerged from these past applications is a strong experience base to design WESPs for high efficiency control of sulfuric acid and particulates for electric utility applications. The base includes both horizontal flow and vertical flow WESPs. Both designs have been shown to achieve high efficiency collection. Site-specific questions regarding WESP layout and physical integration into the gas cleaning system will ultimately decide the best economic choice.

One of the process issues that has surfaced during WESP operation, when dealing with sulfuric acid mist, is a phenomenon known as corona suppression. Corona suppression is not new to electrostatic precipitation. Formation of $SO_3$ vapor together with flue gas moisture will create ultra-fine particles of sulfuric acid mist. This mist can severely suppress operating corona current in the WESP. If present, the corona suppression will decrease collection efficiency in the WESP. Factors that cause or aggravate this condition in a WESP following a wet FGD are large concentrations of fine sulfuric acid mist droplets and a high degree of water mist condensation.[5]

The above effect can be made even more of a problem by improper choices in the design of ESP collection and discharge electrode geometries. By choosing a discharge electrode geometry exhibiting a low corona onset voltage, and by limiting the distance between corona electrode and collecting electrode, corona current can be established and maintained at adequate levels in the inlet fields. This reduces the fine particulate loading exiting the inlet field, thus permitting operation with sufficient power levels in the downstream WESP fields to achieve the overall design collection efficiency. Management of corona suppression is enabled due to past experiences with WESPs but also with dry ESPs on other applications that exhibited the corona suppression problem, such as saltcake (principally sodium sulfate salts) from chemical recovery boilers and dry cement kilns (where fine particulates are found in high concentrations).[6]

## RECENT WESP EXPERIENCE

### AES Deepwater, Texas

AES Deepwater is a petroleum coke fired cogeneration plant located on the Houston Ship Channel in Pasadena, Texas. The plant generates approximately 155 MW of electricity.[2]

This plant utilizes a dry electrostatic precipitator to limit the levels of particulates and unburned carbon entering the limestone-based, gypsum-producing wet FGD system. This plant also uses a wet venturi scrubber prior to the wet FGD to remove additional particulate, HF and HCl. While particulate limits are necessary for regulatory compliance, control of unburned carbon is required to prevent contamination of salable byproduct gypsum.

The petroleum coke fuel has a high vanadium content, which results in relatively high level of $SO_3$ entering the wet FGD where the gas quenching action completes the formation of sulfuric acid mist. Only about 20-30% of the mist is captured in the FGD system because of the fine

particle size of the mist droplets. The inlet concentration of $SO_3$ varies between 35 to 100 ppmvd @ 3% $O_2$ depending on furnace operating conditions and vanadium content in the petcoke.

AES has the oldest operating U.S. installation of a WESP in a power plant application. Table 1 shows the design information and required emission levels. The limit for total particulates including sulfuric acid and condensable was set for 0.005 grains/scfd, thus requiring a collection level of greater than 90% on sulfuric acid alone. Particulate control across the WESP is, typically, in the 95 to 97% range. This is in addition to the high efficiency collection of the dry ESP and the wet venturi scrubber ahead of the wet FGD. Such high efficiency, total particulate control across the system was necessary in 1986 to meet the stringent limits required in this non-attainment area. While the State of Texas required sulfuric acid emissions control to meet the tight particulate limits, to this day there are no federal standards for the control of sulfuric acid mist emissions from such sources.

**Table 1. Specifications for Air Pollution Control System Installed at AES Deepwater.**

| Dry ESP | |
|---|---|
| Inlet gas flow | 634,000 ACFM at 360°F |
| SCA | 376 $ft^2$/1000 ACFM |
| Part. collection efficiency | 97% |
| FGD | |
| $SO_2$ removal efficiency | 90% |
| Pre-scrubber/Quencher | Venturi type, downflow/co-current |
| Tower gas velocity | 9 ft/sec |
| Mist eliminator | Two-stage, chevron type |
| Stack gas reheat | to 175F w/in-line steam reheater |
| Calcium sulfite oxidation | Bleedstream pressure oxidation in separate towers |
| Wet ESP | |
| Gas velocity | 7.7 ft/sec |
| Treatment time | 4.2 sec |
| $SO_3$,ppmv dry @ 3% $O_2$ | 30 to 100 |
| Part. collection efficiency | 98.9% including sulfuric acid mist |
| Outlet loading stopper | 0.005 grains/scfd, including sulfuric acid |

This WESP design consists principally of a three field, upflow system of 12 parallel modules. The collection surfaces are plate-type, fabricated of balsa wood coated with reinforced thermoset plastic. The plates are kept irrigated, for electrical conductivity and removal of collected matter, by a continuous film of water flowing down over the surfaces of the plates. A system of collection trough gutters at the bottom of collector plates removes irrigation water and collected matter from the WESP.

This WESP system has been in successful commercial operation since 1986. Particulate limits were met, and stack opacity is generally maintained well below 10%.

The discharge electrodes and other high voltage internals were made of alloy C-276. After more than 15 years of operation these internals appear new, with no observable signs of corrosion.

In 1999, all of the original collection plates in 1 of the 12 modules were removed and replaced with new alloy collector plates made of 6% Mo stainless steel. AES wanted access to higher performance and lower maintenance cost technology should the need arise in the future. The discharge electrodes in this module were also changed out from the original round wires to higher corona forming strip-type high voltage discharge electrodes. Figure 1 shows the configuration of module B that was retrofitted with alloy collector plates. Figure 2 shows the current-voltage relationship from the inlet to outlet fields. It is seen that corona current increases significantly from the first field to the third field, which is indicative of the effective management of corona suppression, existing though not serious, because of the presence of the sulfuric acid mist fines. While collection performance of the WESP is not an issue, there potential for an even higher corona producing inter-electrode geometry for this unit.

Figure 1: Converted WESP Module at AES Plant

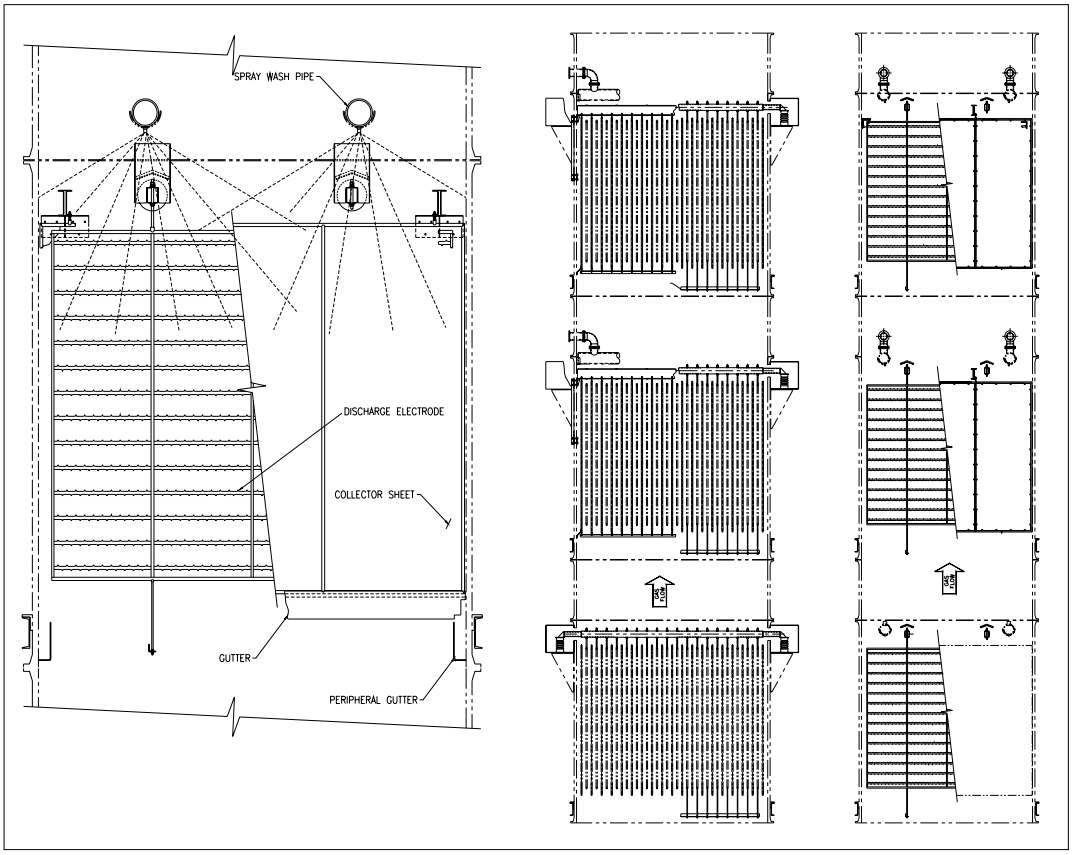
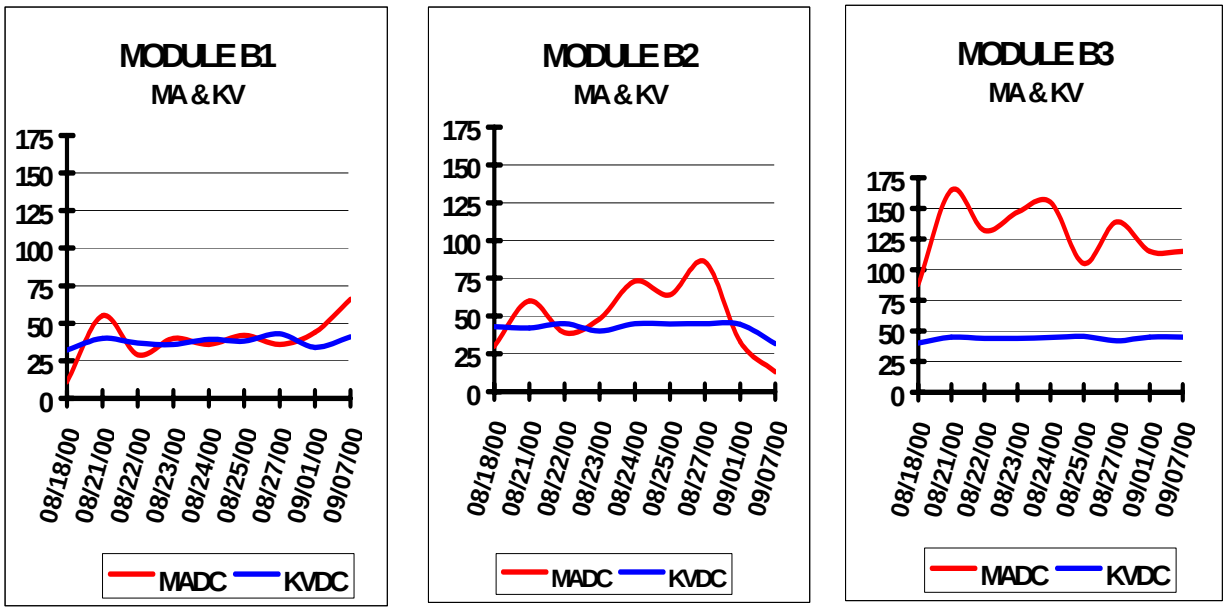


Figure 2: I/V Data form AES WESP




After more than three years of operation on this retrofitted module with all alloy WESP collecting and discharge electrodes, the 6% Mo collector plates have shown no corrosion and still appear as they did when new.

## Northern States Power/Xcel Energy

There are twenty four (24) WESP modules installed at this plant, twelve (12) each on the two 750 MW units. The plant chose the WESP solution to limit its stack opacity below 20%. The approach was to retrofit an upflow, two-field WESP inside an existing casing made available by re-positioning the particulate scrubber internals. Following an initial trial evaluation of WESP technology, the across-the-board retrofit of WESPs began in 1998 and was completed in 2001.

Xcel Energy's Sherbourne County Station is burning sub-bituminous coals having about 20% CaO available in the flyash. The free CaO in this flyash acts to absorb the $SO_3$ in the flue gas. The original high energy, combined particulate/$SO_2$ wet scrubbers alone were unable to limit stack opacity below 20%. There are no dry ESPs installed on these units. By using WESPs, the stack opacity has been limited to levels about 10% as compared to pre-WESP levels of 40%.[7] Particulate control exceeding 90% has been achieved with the one second residence time available within the WESPs' treatment zones.

Due to the high calcium content of the flyash, material scaling occurs in the bottom portion of the first field collector tubes. The first fields primarily capture the re-entrained droplets and carryover from the upstream scrubbers, thus allowing for relatively stable electrical operation in the second fields for fine particulates capture. Each of the modules gets a thorough, off-line manual high pressure washdown about once a year to remove scale. In addition, part of normal daily operation includes a water flushing of modules while the power supplies are de-energized. The alkaline nature of flyash and absence of sulfuric acid mist allowed the use of 304 L for the

WESP internals for this application. Lessons learned from this experience are: 1) WESP is able to overcome difficult conditions for dust build-up through well scheduled wash downs, and 2) high efficiency non-acid particulate collection, in addition to sulfuric acid mist collection, is an important capability to consider when evaluating WESPs for sulfuric acid collection.

## Northwestern U.S. Petroleum Refinery

A petroleum coke calciner produces flue gas containing $SO_2$ that is treated with a caustic reagent scrubber. While the scrubber is highly efficient in absorbing $SO_2$, it cannot adequately capture the sulfuric acid mist. Since 1998, a WESP has been used to achieve a high degree of sulfuric acid capture to eliminate the visible plume. Three parallel WESP modules in a single field, upflow configuration are utilized. Figures 3 and 4 show the excellent particulate and sulfuric acid capture across the WESP. Sulfuric mist emissions were limited to levels of approximately 1 ppmvd @ 7% $O_2$, and particulate concentrations were reduced to levels well below 0.005 grains/scfd.

The material of construction of these WESPs' internals and casing is alloy 904 L. The corrosion resistance has been very good, once again, observably in "like new" condition upon inspection.

Figure 3: WESP Data on Sulfuric Acid from Refinery in Northwest U.S.

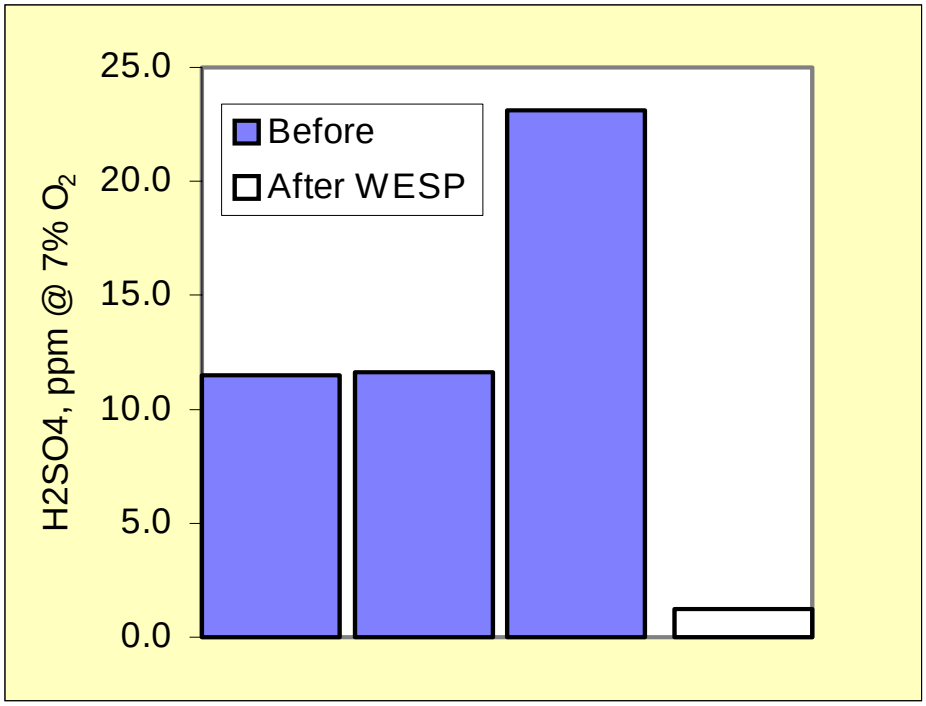
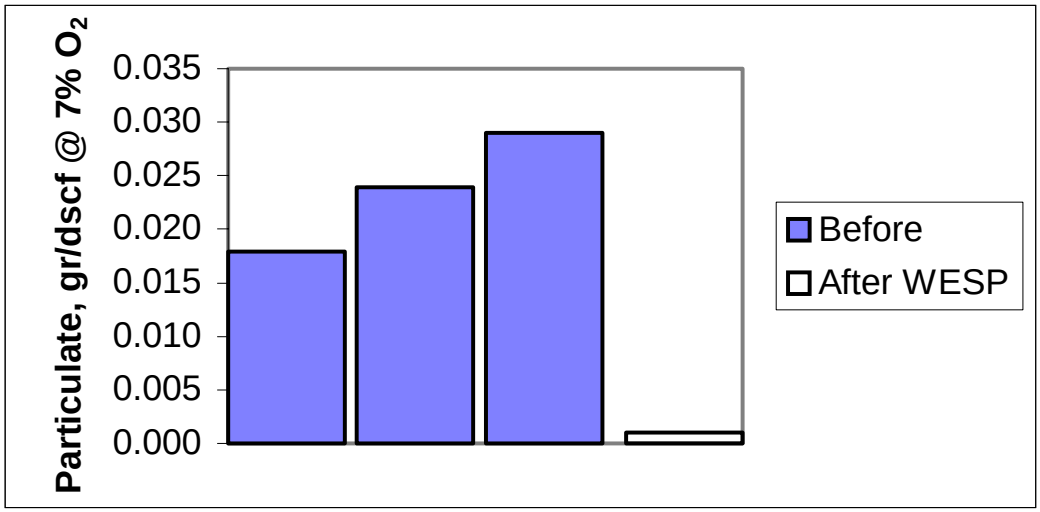


Figure 4: WESP Data on Particulate from Refinery in Northwest U.S.




## New Brunswick Power, Coleson Cove

In 2002, New Brunswick Power elected to install high efficiency WESPs following two new limestone-based wet FGD scrubbers at their 1050 MW Coleson Cove station. This was part of a plantwide effort to reduce the cost of electricity generation by switching to lower cost Orimulsion™ fuel while considerably reducing $SO_X$ and particulate emissions. New Brunswick Power's decision to install the WESPs was to assure control of sulfuric acid emissions below 5 ppmvd @ 3% $O_2$, and limit flyash particulates below 0.015 lb/MBtu. To achieve this level of control on sulfuric acid at all times, collection efficiency requirements will exceed 90%.

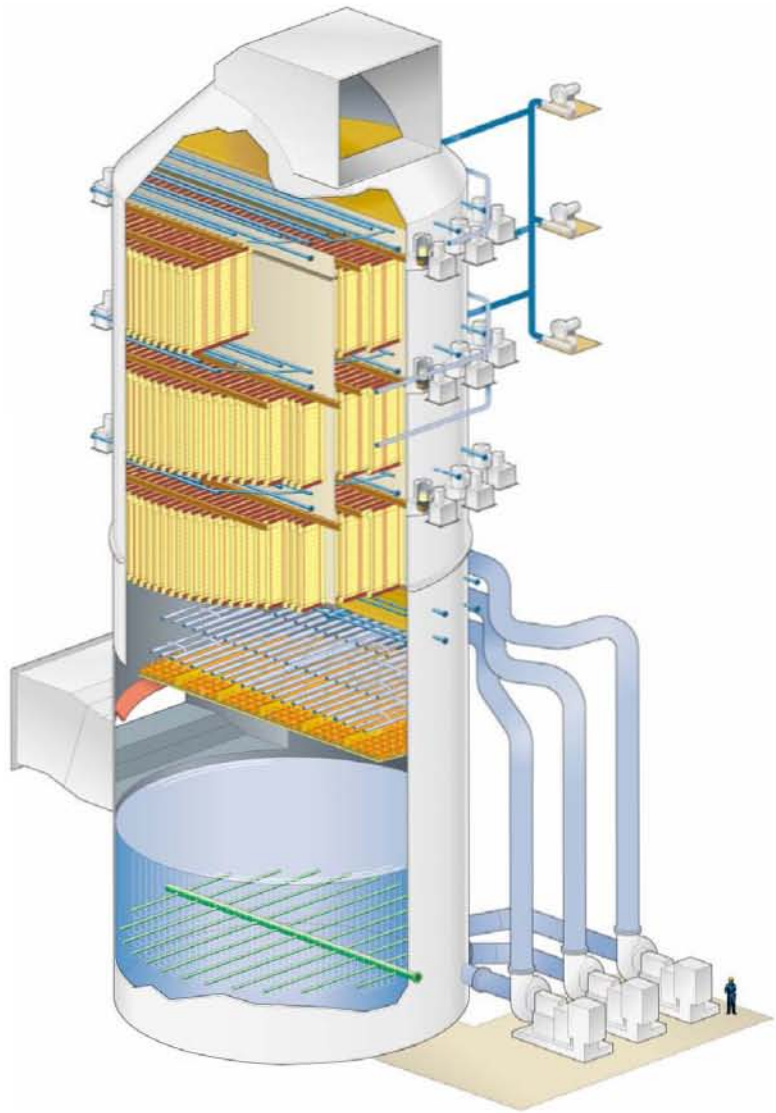
Coleson Cove will be the second power plant at which New Brunswick Power has installed a WESP system for the collection of acid mist following a wet FGD. A smaller, single-field WESP system went into operation at its Dalhousie plant in the year 2000 which followed that plant's conversion to Orimulsion™ firing and wet FGD installation in 1994.

Figure 5 shows a schematic of the layout for the Coleson Cove plant for each of the two wet FGD absorbers. It can be seen that the wet ESP consists of a three field upflow design, similar to the design that has been in successful use for more than 15 years at the AES Deepwater facility. Scrubbed flue gas enters the inlet field of WESPs after exiting the wet FGD mist eliminator.

There are three electrical fields in series and four independently energized high voltage bus sections across each WESP electrical field. This conservatively sectionalized, twelve (12) bus section design allows for small sections to be de-energized during periodic water flushings while maintaining overall emissions within design levels.

The gas exits the top of the WESP through a final mist eliminator section which captures any re-entrained droplets that may be present during flushing cycles, and transitions directly into the stack through an outlet hood. This design simplifies and lowers the balance of plant costs which would otherwise be associated with a conventional arrangement where the WESP may be placed on a stand-alone basis and outside of the wet FGD vessel.

Figure 5: Upflow WESP Integrated with WFGD



The Coleson Cove plant is located on a shoreline, where layout space was at a premium. Therefore, this integrated arrangement between the wet FGD absorber and WESP made the most sense.

The material of construction of collecting plates at the inlet field will be C-276. Stainless steel made of 6% Mo is utilized for the high voltage systems and the balance of the collection plates.

Construction of the integrated wet FGD/WESP systems will begin in spring of 2003. The systems will be operational by September 2004.

It is expected that this integrated, multi-pollutant approach to wet FGD installations will become more common in future fossil fired power plants and as a retrofit where multiple control of NOx, SOx, mercury and fine particulates of flyash and sulfuric acid may be required.

## COMPARISON OF WESP VERSUS SORBENT INJECTION OPTIONS

Studies have investigated the possibility of sulfuric acid emission reductions through the use of additives that allow existing air pollution control equipment to trap the resultant particulate matter. In this way, the retrofit of another piece of capital equipment such as the WESP could be avoided.

A pilot testing study commissioned by the Electric Power Research Institute (EPRI) at its high sulfur test center in New York more than ten years ago is still relevant to determine the effectiveness of various sorbents for the removal of $SO_3$ and its associated plume.[9] More than ten years later, a full-scale evaluation was commissioned by American Electric Power at its Gavin station to evaluate the effectiveness of control of sulfuric acid mist following the installation of retrofitted SCRs.[1, 10] This installation also has an existing wet FGD system for $SO_2$ control.

A summary of the above studies is provided below and will be used as a basis to compare the economics of the alternatives:

a. To remove $SO_3$ from flue gas in a utility boiler application, alkaline sorbents can be injected either in the upper furnace or ahead of the dry ESP.
b. Hydrated lime, ammonia and sodium bicarbonate were injected ahead of the dry ESP, while magnesium hydroxide was injected in the furnace sections.
c. Injection of hydrated lime caused a significant loss of dry ESP performance, which relies on the effect of free sulfuric acid for lowering flyash resistivity levels. Emissions were increased several fold due to increased flyash resistivity and particulate loading to the dry ESP. Therefore, it may be necessary to consider the cost of ESP enlargement, or other means, to restore or improve the original particulate collection performance.
d. Injection of ammonia, while most efficient because of the gas/gas reaction for the absorption of $SO_3$, affects dry ESP performance due to creation of ultra fine ammonium bisulfate particulates. This can reduce the inlet corona current in the dry ESP due to corona suppression. In addition, increased stickiness of ash can create ESP performance and/or maintenance problems and also ash handling system problems.
e. There is motivation among the utilities to increase the amount of flyash utilization. Flyash utilization as cement raw material substitute is likely to show gains in energy use, and thus contribute to the overall goal of $CO_2$ mitigation. Both ammonia and sodium compounds in ash have resulted in ash being unsuitable for use. In several plants that are already utilizing a salable flyash, this presents a double problem of loss of ash revenue and increased cost of ash disposal. (This impact will be included for analysis when evaluating sodium based sorbents.)
f. Magnesium hydroxide injection in the furnace yields results similar to hydrated lime injection ahead of the ESP.

## ECONOMIC EVALUATION OF ALTERNATIVES

The following evaluation focuses on comparing the cost of WESP technology versus sodium bicarbonate and hydrated lime injection. The results for magnesium hydroxide and ammonia have a similar impact, the former being analogous to lime and the latter to sodium bicarbonate.

The capital cost of wet ESP is annualized, and added to this are anticipated annual operating costs to generate the annual cost to own and operate the WESPs. A capital recovery factor of 0.1 is used to generate annualized cost of capital. For a levelizing period of 15 to 20 years, and a difference between interest and discount rates of 6%, this factor is considered reasonable and conforms within EPRI guidelines. Operating costs for WESP power supplies, controllers, and high voltage insulator heaters are included in the evaluation.

Comparison is made of the WESP annual costs to the annualized cost of sorbent injection technology. Impacts of ESP enlargements and loss of ash sale are included as appropriate.

Table 2 shows the estimated total installed cost of WESP of the design as shown for Coleson Cove for three different levels of collection efficiency. For a 50% collection efficiency, a single field unit will suffice. For a collection efficiency requirement of 80%, a two field unit will be necessary. For achieving collection efficiency of sulfuric acid exceeding 90% collection, a three field unit will be required.

**Table 2. Approximate Total Installed Cost Comparison of Wet ESPs vs. $SO_3$ Collection Efficiency (500 MW Plant).**

| Number of fields | $SO_3$ Collection efficiency, % | $/kW |
|---|---|---|
| 1 | 50 | 20 |
| 2 | 80 | 30 |
| 3 | 95 | 40 |

Notes:

1. These values based on 6% Mo internals.
2. $/kW figures based on "greenfield" construction maximizing modular construction.
3. $/kW figures based on the WESP component portion of a total WFGD/WESP integrated system.

Table 3 shows the injection rates of dry hydrated lime and sodium bicarbonate to achieve the above mentioned $SO_3$ collection efficiency levels. It is readily seen that required injection rates increase rapidly as the $SO_3$ collection efficiency requirements exceed 50%.

**Table 3. Sorbent Injection Rates for Achieving Stated Levels of $SO_3$ Removal.**

| Sorbent type, $SO_3$ collection efficiency,% lb/hr/1000 ACFM | | | |
|---|---|---|---|
| | 50% | 80% | 95% |
| Hydrated lime | 1.5 | 3 | 6 |
| Sodium bicarbonate | 3 | 5 | - |

Notes:
Injection takes place ahead of the dry ESP around 300 to 350 deg F.
All dry process.
Capital costs of sorbent injection system estimated at 5$/kW.

In the sorbent injection approach it is assumed that an injection temperature of 310F is maintained. It is known that increasing the residence time to aid gas/solids mixing ahead of the dry ESP will reduce sorbent injection rates and associated costs. It is further assumed that this situation already exists at the plant. Additional costs may be incurred for ductwork modifications if this situation does not exist and provisions for increased residence time are required.

The following assumptions are made in the analysis:

- A 500 MW unit is considered in this example.
- An existing dry ESP of 250 SCA ($ft^2$/1000 ACFM) is keeping particulate limits below 0.03 lb/MBtu
- Additional 30% increase in treatment time will be needed to restore the ESP performance after lime sorbent injection.
- Ash disposal costs are at 10$/ton of ash
- Ash utilization of 50% of the ash can be done at this plant at a price level of 5$/ton ash.
- Bituminous coal results in ash content into the ESP of 10 lb/MBtu.
- The plant operates 8000 hours per year
- Hydrated lime can be purchased for 100 US$/ton delivered
- Sodium bicarbonate can be purchased for 250 US$/ton delivered.

Table 4 shows the annualized costs to own and operate the WESPs, dry lime system and sodium bicarbonate system. It is seen that if a particular plant must maintain its ash sale, or maintain its pre-injection particulate limits after sorbent injection, the WESP has considerably lower cost to own and operate when compared to the sorbent injection techniques shown here. This is true for the levels of $SO_3$ collection efficiency discussed above.

The fact that total particulate emissions from the WESP are several times lower than the dry solution is not factored into this economic analysis.

The economics favor the WESP technology even more for the 80% and 90% removal cases, because the sorbent utilization efficiency decreases for higher levels of $SO_3$ removal. Again, no credit has been applied to the WESP technology to reflect the fact that stack particulate emissions are much lower than with the sorbent technology.

An additional factor that may promote the use of WESP technology is that droplet carryover from the wet FGD is captured at a high efficiency in the WESP. To the extent soluble ionic mercury is readily captured in the wet ESP, overall system improvements in mercury capture are to be expected. This mechanism is unavailable in the sorbent injection technology.

## CONCLUSIONS

- WESPs have been a proven technology for the collection of sulfuric acid mist for nearly 100 years.
- The use of WESPs to limit total particulates, including sulfuric acid mist, in conjunction with a wet FGD system is becoming increasingly relevant to electric utility plants.

**Table 4. Economic Analysis of Options for $SO_3$ Control, 500MW Plant Operating 8000 hrs/year (Collection Efficiency Requirements, %; All numbers reported in M$USD).**

| | 50 WESP | LIME | Sodium | 80 WESP | LIME | Sodium | 95 WESP | LIME | Sodium |
|---|---|---|---|---|---|---|---|---|---|
| Capital costs | 10 | | | 15 | | | 20 | | |
| ESP Upgrade | | 3.1 | | | 3.1 | | | 3.1 | |
| Sorbent System | | 2.5 | 2.5 | | 2.5 | 2.5 | | 2.5 | 2.5 |
| | | | | | | | | | |
| Total Capital | 10 | 5.6 | 2.5 | 15 | 5.6 | 2.5 | 20 | 5.6 | 2.5 |
| | | | | | | | | | |
| Total Capital Recovery | 1 | 0.56 | 0.25 | 1.5 | 0.56 | 0.25 | 2 | 0.56 | 0.25 |
| (0.1 factor) | | | | | | | | | |
| Operating costs | 0.12 | | | 0.16 | | | 0.2 | | |
| | | | | | | | | | |
| Sorbent | | 0.99 | 4.95 | | 1.98 | 8.25 | | 3.96 | 13.22 |
| Ash Loss of Sale | | | 0.425 | | | 0.425 | | | 0.425 |
| Ash Disposal | | | 0.678 | | | 0.678 | | | 0.678 |
| | | | | | | | | | |
| Total Operating Costs | 0.12 | 0.99 | 6.053 | 0.16 | 1.98 | 9.353 | 0.2 | 3.96 | 14.303 |
| | | | | | | | | | |
| Total Costs to Own and Operate | 1.12 | 1.55 | 6.303 | 1.66 | 2.54 | 9.603 | 2.2 | 4.52 | 14.553 |

Notes: 1) Hydrated lime at 100$/ton, sodium bicarbonate at 250 $/ton, 10 tons per hr of ash for utilization at 5 $/ton, 10 tons per hour at 7 $/ton.
2) 3300 ACFM per MW used to calculate gas flow.
3) 250 SCA ESP. 30% more treatment time needed for ESP upgrade, upgrade at 25$/ft$^2$
4) Basis: 6% Mo WESP internals.

- WESPs integrated with wet FGD absorbers are an economical alternative in terms of capital and operating costs, and plant layout restrictions, when compared to "stand-alone" WESPs.
- In spite of the higher capital costs, WESPs are more economical to own and operate when compared with hydrated lime and sodium bicarbonate injection technologies.
- Power plants should consider impacts of sorbent injection technologies due to potential loss of ash sales, as well as adverse impacts on the dry ESP performance.
- The additional benefits in keeping solid particulates at very low levels, and possible benefits in mercury control, will make the WESPs a desirable choice when considering the available options for $SO_3$ control.
- Requirements for future operating permits may address emissions of $PM_{2.5}$, $SO_3$ and visible plume. WESP technology addresses all of these emissions.

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**OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE**
**OFFICE OF AIR QUALITY PLANNING AND STANDARDS**

# PM CEMS INSTALLATIONS, CERTIFICATIONS, AND OPERATIONS

**Status Report**

**Updated, September 27, 2005**

Zofia Kosim (202-564-8733)
Dan Bivins (919-541-5244)

## PURPOSE OF THIS DOCUMENT

The purpose of this document is to present and summarize the successful installations, certifications, and operations of the particulate matter continuous emission monitoring systems, (PM CEMS), to date. We expect this document will help the regulatory, permitting, and enforcement authorities, and the industry to make appropriate decisions regarding PM CEMS. We will update this documents periodically until PM CEMS are effectively implemented. The technical lessons learned from the installations of PM CEMS will be described in detail in another EPA document, also to be periodically updated, "The Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring" - EPA-454/R-00-039.

## 2. INTRODUCTION

PM CEMS have been used in Europe since the 1960s and became a requirement in Germany in the mid 1970s ("Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring" - EPA-454/R-00-039). EPA presently requires PM CEMS on hazardous combustors and portland cement plants under the MACT regulations, but these requirements have been deferred until EPA amends these rules. A few PM CEMS have been installed in the U.S. under the Title V permit or as alternative monitoring methods. Several other PM CEMS have been installed under the EPA utility boiler Enforcement Initiative. In addition, EPA has recently proposed and asked for public comment on amendments to the NSPS boiler regulations (Subparts Da, Db, and Dc) on the issue of requiring PM CEMS on power boilers.

## 3. WHAT ARE PM CEMS

PM CEMS are used for determining compliance with PM emission limits and are installed and certified according to the EPA performance specifications. U.S. EPA has developed the performance specifications and QA/QC procedures to insure that PM CEMS continuously provides valid data points on PM emissions from a source.

Any regulatory CEMS must be operated and evaluated according to performance specifications and compared to an appropriate EPA reference test method. EPA proposed performance specifications for PM CEMS, PS-11, on April 19, 1996, as part of the Hazardous Waste Combustion MACT standard. The PS-11 specifications (along with the Part 60 Appendix F Procedure 2, which provides additional QA/QC procedures) were finalized on January 12, 2004. Before PS-11 was finalized, EPA conducted tests of several different PM CEMS at hazardous waste combustors and conducted a test involving 3 different PM CEMS at a power plant. The results from these tests and EPA's experience are reflected in PS-11.

A PM CEMS, located on or near a stack, continuously draws samples of the flue gas from the stack or measures in-situ and analyzes it for PM. The sampling procedures vary, depending on the type of the PM CEMS. The most common analytical techniques used in PM CEMS include beta attenuation, light scattering, and scintillation methods. The conditions in the stack dictate the selection of an appropriate PM CEMS, as required by PS -11. A PM CEMS must be appropriate for the stack conditions and installed in a suitable location. An improperly selected or improperly located PM CEMS will not provide quality data and may have difficulty with correlation to PM.

Thus far, several facilities have installed PM CEMS. Among those facilities are hazardous waste incinerators (Eli Lilly, Oak Ridge), a pulp and paper mill in Florida (Rayonier), and a few power plants. Two power plants owned by Dominion Corporation installed PM CEMS under a Consent Decree related to the Utility Enforcement Initiative. These facilities have successfully certified their PM CEMS. These facilities represent a variety of stack and control device applications with both wet and dry stack conditions. Presently a few power plants owned by Wisconsin Electric and Power Company are finalizing the installation of their PM CEMS under another Consent Decree and are about to start testing the instruments. A first PM CEMS on a utility boiler was installed at TECO but, since that installation is still under a legal discussion, the details of the TECO instrument's operation are not part of this document. We will update this document to reflect the results of these discussions as appropriate.

Until quite recently, there were not many PM CEMS suppliers in the U.S. Today, several new PM CEMS are offered for sale by different manufacturers. These newer PM CEMS are suitable for either wet stack conditions (e.g., PM CEMS offered by MSI, Forney Corporation, or Sick/Maihak) or for dry stack conditions (e.g., PM CEMS offered by ESC Corp., SICK Corp., Land Instruments Corp or MSI.). The cost of PM CEMS (particularly for the dry stacks) has gone down and are in the range of an average COMS monitor. The Eli Lilly Company, the Dominion power plants, and the Wisconsin Electric power plants, have installed a variety of PM CEMS instruments, suitable for their respective stack conditions.

## 4. EXAMPLES OF CURRENT INSTALLATIONS, CERTIFICATIONS, AND OPERATIONS OF PM CEMS

- One of the power plants that installed PM CEMS under a Consent Decree, is Dominion

Electric (Dominion). Dominion installed the CEMS on its two power plants in West Virginia: Mt. Storm and Chesterfield. The correlations tests of the Dominion's PM CEMS were conducted using the promulgated PS-11 and approved plans (attachment 1).

The Chesterfield's base loaded unit 5 is a 359 MW coal-fired boiler equipped with an electrostatic precipitator, ESP, and a seasonal selective catalytic reduction, SCR, system to reduce the emissions of nitrogen oxides. The Consent Decree's PM emission limit is 0.1 lb/mmBtu. Dominion installed two light scattering PM CEMS on the stack of unit 5: the P-5B supplied by ESC and Premier 2400 supplied by Land Instruments. Both instruments are optical devices suitable for dry stacks. Dominion conducted the correlation tests in the fall of 2004, using the TEOM instrument, and produced several successful correlations for both PM CEMS (attachment 2).

The coal-fired, base loaded units 1 and 2 at Mt Storm share a common wet stack where Dominion installed the MSI BetGauge PM CEMS. The PM CEMS test plan for Mt. Storm (attachment 2) describes the details of the installation. Both units are 550 MW and each is equipped with flue gas desulfurization (FGD) system, an ESP to control PM control and an ozone season SCR to control NOx emissions. The PM limit for both units is 0.05 lb/mmBtu. Mt Storm performed the correlation test on October 5-9, 2004 and he PM CEMS very comfortably passed the acceptance criteria while the obtained correlation was linear (attachment 3). Mt Storm performed a quarterly RRA audit test May 31-June 1, 2005 and very comfortably passed the acceptance criteria confirming that the correlation relationship is being maintained.

Dominion has already submitted emission reports and they indicate no problems with meeting the emission limit (example is in attachment 4)

- Eli Lilly approached EPA asking for an approval of a PM CEMS as an alternative to the parametric monitoring for the PM standard required under the hazardous combustor MACT rule (40 CFR Part 63 Subpart EEE and General Provisions). The monitor Eli Lilly installed is a light-scattering device, Sigrist KTNR. Eli Lilly has operated the same type of PM CEMS on its facility in Europe and has acquired a significant experience before applying for using it as an alternative monitoring method. Ely Lilly also hosted one of the test of several PM CEMS in the 1990's for the hazardous combustion rule where it gained experience operating the PM CEMS. Recently, EL established a preliminary calibration correlation for their PM CEMS while the incinerator was burning surrogate material (natural gas, liquid waste, solid waste, fuel oil but not hazardous waste). The reference test method was 5i. The correlation was conducted as outlined in PS-11 and using dual train samplers. The results indicated that the Sigrist PM CEMS met all of the correlation requirements for a linear, polynomial, and log correlations. The best fit was linear (attachment 5), which is the correlation presently in use at Lilly.

- Rayonier, a pulp and paper plant in Florida, obtained a Title V permit with a requirement to operate a PM CEMS under the CAM rule. The permit conditions did not require Rayonier to fully comply with the requirements of PS-11, so the facility conducted only 9 out of the required at least 15 test runs. When a new MACT regulation ( 40 CFR Part 63

Subpart MM) became applicable to Rayonier, the plant requested an EPA approval of the PM CEMS as an alternative monitoring method to the required parametric monitoring on its recovery boiler. To obtain the approval, Rayonier needed to conduct the remaining tests. Upon completing the remaining tests and a successful correlation, EPA approved the PM CEMS as an alternative monitoring method (attachment 6).

- The U.S. DOE conducted a 15-month study in 1990-2000 of three commercially available PM CEMS at its TSCA incinerator at the East Tennessee Technology Park in Oak Ridge, Tennessee. The incinerator treats PCB-contaminated RCRA hazardous low-level radioactive waste. The three systems chosen for evaluation included the Durag F-904-K beta gauge, the ESA Beta 5M, and the Sigrist CTNR light scattering device. The performance was evaluated using the draft version of PS-11 and Procedure 2. Both beta gauge units passed the PS-11 correlation test criteria for the linear and polynomial models (attachment 7). The Sigrist CNTR did not pass PS-11. Upon the test, Oak Ridge permanently installed an MSI BetaGuard instrument, designed to meet the requirements of PS-11 and Procedure 2, and the instrument will be tested in the fall of 2005.

- We Energies has installed PM CEMS on the common stack of units 5 and 6, on the precipitator outlet ducts of units 7 and 8 at the Oak Creek facility, as well as one PM CEMS on the common stack for units 1 and 2 at its Pleasant Prairie plant. We Energies will soon install more PM CEMS to comply with the Consent Decree. The units at Oak Creek and Pleasant Prairie will tested the Oak Creek PM CEMS in June and the Pleasant Prairie monitor afterwards (according to the approved test plan, attachment 8, and emission test notification). We will immediately update this document to reflect the results of these tests when the data become available.

- More Consent Decrees with power plants, other forms of enforcement actions against power plants, and some Title V permits for a number of power plants or an alternative monitoring request approvals require PM CEMS (for example the Longview Power, LLC in Maidsville, WV, attachment 9, the Mill Creek plant of the Louisville Gas and Electric Company, KY, or Henderson Station II of Western Kentucky Energy, KY).

- There is also a few of Title V permits and/or orders for non-utilities that require the installation, certification, and operation of PM CEMS. We will immediately update this document to reflect the results of these tests as they become available.

Attachments:

1. Chesterfield Unit 5 and Mount Storm Units 1&2 Particulate Matter Monitoring Plan, March 30, 2004

2. Chesterfield test results

3. Mt. Storm Units 1 & 2, PM CEM Calibration Testing, Summary of Results

4. Dominion emission test results (an example)

5. Eli Lilly correlation test results

6. Approval of PM CEMS at Rayonier as an alternative monitoring method with the PM CEMS correlation results

7. Oak Ridge preliminary PM CEMS test results (selected pages)

8. EPA-approved test plan for We Energies (Oak Creek and Pleasant Prairie plants)

9. Longview Power, PM CEMS-related Title V permit requirements (selected pages)

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

| | | |
|---|---|---|
| UNITED STATES OF AMERICA, | ) | |
| | ) | |
| Plaintiff, | ) | |
| | ) | CIVIL ACTION NO. 99-2524 |
| v. | ) | CIV-T-23F |
| | ) | |
| | ) | |
| TAMPA ELECTRIC COMPANY, | ) | |
| | ) | |
| Defendant. | ) | |
| | ) | |

**CONSENT DECREE**

WHEREAS, Plaintiff, the United States of America ( Plaintiff or the United States ), on behalf of the United States Environmental Protection Agency ( EPA ) filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company ( Tampa Electric ) commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration ( PSD ) requirements at Part C of the Clean Air Act ( Act ), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the NOV );

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm s length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will

avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric s decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric s existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and

electrostatic precipitators that serve all existing coal-fired electric generating Units at the company s Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric s existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent

Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

## I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

## II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United

States and upon Tampa Electric, its successors and assigns, and Tampa Electric s officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric s responsibilities under this Consent Decree, including liabilities for nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions

necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

## III. DEFINITIONS

4. Alternative Coal shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. BACT Analysis shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. Big Bend shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. Consent Decree shall mean this Consent Decree and the Appendix thereto.

8. Emission Rate shall mean the average number of pounds of pollutant emitted per million BTU of heat input ( lb/mmBTU ) or the average concentration of a pollutant in parts per million by volume ( ppm ), as dictated by the unit of measure specified for the rate in question, where:

A. in the case of a coal-fired, steam electric generating unit, such rates shall be

calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

B. in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

C. the reference methods for determining Emission Rates for $SO_2$ and $NO_x$ shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

D. nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. EPA shall mean the United States Environmental Protection Agency.

10. Gannon shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and

equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon Bayside Power Station upon completion of the Re-Powering required under this Consent Decree.

11. lb/mmBTU shall mean pounds per million British Thermal Units of heat input.

12. NOx shall mean oxides of nitrogen.

13. NOV shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. PM shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. ppm shall mean parts per million by dry volume, corrected to 15% $O_2$.

16. Project Dollars shall mean Tampa Electric s expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of $NO_x$ from Big Bend Units 1 through 3) and in Section VII of this Consent Decree ($NO_x$ Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric s properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. PSD shall mean Prevention of Significant Deterioration within the meaning of Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. Re-Power shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. Reserve / Standby shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. SCR shall mean Selective Catalytic Reduction.

21. Shutdown shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. S $O_2$" shall mean sulphur dioxide.

23. Title V Permit shall mean the permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq.

24. Total Baseline Emissions shall mean calendar year 1998 emissions of $NO_x$, $SO_2$, and PM comprised of the following amounts for each pollutant:

A. for Gannon: 30,763 tons of $NO_x$, 64,620 tons of $SO_2$, and 1,914 tons of PM; and

B. for Big Bend: 36,077 tons of $NO_x$ , 107,334 tons of $SO_2$, and 3,002 tons of PM.

25. Unit shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

## IV. EMISSIONS REDUCTIONS AND CONTROLS GANNON AND BIG BEND

### A. GANNON

26. Consent Decree-Required Re-Powering of Gannon. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW ( Megawatt ), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this

Subparagraph A.

B. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for $NO_x$ of no greater than 3.5 ppm.

C. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

D. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a $NO_x$ Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the $NO_x$ Emission Rate established in the PSD Permit or an Emission Rate for $NO_x$ of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa

Electric shall not combust coal in the operation of any Unit at Gannon.

**B. <u>BIG BEND</u>**

29. <u>Initial Reduction and Control of $SO_2$ Emissions from Big Bend Units 1 and 2</u> . Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of $SO_2$ from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the $SO_2$ contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

(2) must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

B. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control $SO_2$ emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

C. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of

Alternative Coal.

D. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of $SO_2$ Emissions from Big Bend Unit 3. Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of $SO_2$ from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the $SO_2$ contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all $SO_2$ contained in the flue gas entering the scrubber is removed or the Emission Rate for $SO_2$ for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the $SO_2$ contained in the flue gas entering the scrubber is removed or the Emission Rate for $SO_2$ does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa

Electric:

(1) does not operate Unit 3 during outages on more than thirty (30) calendar days, or any part thereof, in any calendar year; or

(2) must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

B. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control $SO_2$ emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

C. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B

shall not apply to Unit 3.

D. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of $SO_2$ from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA. Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which $SO_2$ emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the

scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA s approval of the plan or any phase of the plan, Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. <u>PM Emission Minimization and Monitoring at Big Bend</u>.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa

Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational

practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study s recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric s Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. Continuous operation of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a

proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric s annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal.

Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. Reduction of $NO_x$ at Big Bend Unit 4 after 2005 Election. Based on Tampa Electric s election in Paragraph 33, Tampa Electric shall take one of the following actions:

A. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of $NO_x$ from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for $NO_x$ from Unit 4 no greater than 0.10 lb/mmBTU; or

B. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a $NO_x$ Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for $NO_x$ of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

C. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007.

Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for $NO_x$ of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

D. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. Early Reductions of $NO_x$ from Big Bend Units 1 through 3: On or before December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce $NO_x$ emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million

Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the $NO_x$ Emission Rate by at least 30% when compared against the $NO_x$ Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the $NO_x$ Emissions Rate by at least 15% when compared against the $NO_x$ Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the $NO_x$ Emission Rates specified in this Paragraph for all three Units, then Tampa Electric s plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric s plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. <u>Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal</u>. Tampa Electric shall advise EPA in writing, on or before May 1,

2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further $NO_x$ Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of $NO_x$ to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of $NO_x$ on each such Unit no less stringent than 0.10 lb/mmBTU.

B. Notwithstanding Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of $NO_x$ at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the installation cost ceiling contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If

Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

C. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the installation cost ceiling, Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a $NO_x$ Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric s determination, including all documentation sufficient to replicate and evaluate Tampa Electric s cost projections.

D. Unless EPA contests Tampa Electric s determination that the installation cost ceiling will be exceeded by installing control equipment to reduce $NO_x$ emissions to 0.10 lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the $NO_x$ control technology designed to achieve the lowest Emission Rate that can be attained within the installation cost ceiling. Notwithstanding any provision of this Consent Decree, including the installation cost ceiling, Tampa Electric shall install $NO_x$ control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its $NO_x$ controls shall meet the Emission Rate for which they

are designed.

E. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for $NO_x$ at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric s $NO_x$ Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3 . If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a $NO_x$ Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for $NO_x$ of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this

Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for $NO_x$ of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit.

For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. Further $SO_2$ Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the $SO_2$ in the flue gas that entered the scrubber; or

(2) the Emission Rate for $SO_2$ from each Unit does not exceed 0.25 lb/mmBTU.

B. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of $SO_2$ from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control $SO_2$ emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without

its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

C. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control $S0_2$ emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control $S0_2$ emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

D. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

## C. BIG BEND AND GANNON -- PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force

Majeure provisions of this Consent Decree.

42. Title V Permits.

A. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

B. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

C. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff s civil claims

for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

B. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

C. have arisen from Tampa Electric s actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue . The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

(1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

(2) such change is commenced, within the meaning of 40 C.F.R. Section

52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of $NO_x$, $SO_2$, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII ( Termination ), the provisions of Paragraph 44 ( Resolution of Future Claims - Covenant Not to Sue ) shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to

upgrading of ESPs and scrubbers, installation of $NO_x$ controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting $NO_x$ or $SO_2$ emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. $SO_2$ credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric s own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level $NO_x$ and $SO_2$ controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or

selling emission allowances arising from Tampa Electric s activities occurring prior to December 31, 1999, or Tampa Electric s activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the $SO_2$ scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

## V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric s report shall be signed by Tampa Electric s Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

## VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric s responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

## VII. $NO_x$ REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the $NO_x$ Reduction and Other Mitigation Projects (referred to together as Projects ) described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this

Consent Decree. In performing these Projects, Tampa Electric shall spend no less than $10 million in Project Dollars, in total, unless the Additional $NO_x$ Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than $5 million, in which case Tampa Electric shall spend no less than $10 million but no more than $11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

A. Early $NO_x$ reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

B. Performance of Air Chemistry Work in Tampa Bay Estuary. Tampa Electric shall expend no more than $2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this

work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric s payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional $NO_x$ Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative $NO_x$ control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the $NO_x$ Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(2) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative $NO_x$ control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the $NO_x$ demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in $NO_x$ or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph

alters Tampa Electric s obligation under Paragraph 26 of this Consent Decree.

(3) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the $NO_x$ demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in $NO_x$ or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative $NO_x$ control technology or reduce the $NO_x$ Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(4) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric s results in implementing the project, including the emission reductions or other environmental benefits

achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

## VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

B. For all violations of a 24 hour Emission Rate (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

C. For all violations of 30-day rolling average Emission Rates (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same

source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

D. For all violations of a 95% removal efficiency requirement (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

E. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity $27,500 per day, per violation.

F. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and 42 $1,000 per day, per violation.

G. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

H. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

I. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

J. Failure to submit quarterly progress and monitoring report $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

K. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

L. Failure to perform $NO_x$ reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional $NO_x$ Reductions Project(s)), $10,000 per day, per violation;

M. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

N. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest

shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required to remit any stipulated penalty to the United States that is disputed in compliance with Part XI of this Consent Decree until the dispute is resolved in favor of the United States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

## IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a

period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric s facilities under Section 114 of the Act, 42 U.S.C. § 7414.

## X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force

Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances

beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric s response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

## XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting

to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that

occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

## XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for

injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. §

50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA

Director, Air Enforcement Division

Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply

to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

## XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims), this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric s certification, the Court shall order that this Consent Decree be terminated on

Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF _____ 2000.

_____

UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

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THROUGH ITS UNDERSIGNED REPRESENTATIVES, THE UNITED STATES AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE:

FOR PLAINTIFF
UNITED STATES OF AMERICA:

_____ Date: _____

Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources
Division
United States Department of Justice

_____

W. Benjamin Fisherow
Assistant Chief
Thomas A. Mariani, Jr.
Jon A. Mueller
Senior Attorneys
Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044
(202) 514-4620

Donna A. Bucella
United States Attorney for the
Middle District of Florida

By:_____
Whitney L. Schmidt
Affirmative Civil Enforcement Coordinator
Assistant United States Attorney
United States Attorney s Office
Middle District of Florida
Florida Bar No. 0337129
Tampa, Florida 33602
(813) 274-6000
(813) 274-6198 (facsimile)

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

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_____

Steven A. Herman
Assistant Administrator for Office of Enforcement
and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

_____

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

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_____

John H. Hankinson
Regional Administrator
U.S. Environmental Protection Agency (Region IV)
Atlanta, Georgia

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

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THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

_____ Date: _____

John B. Ramil
President
Tampa Electric Company

_____

Sheila M. McDevitt
General Counsel
Tampa Electric Company

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF NORTH DAKOTA

| | | |
|---|---|---|
| UNITED STATES OF AMERICA and STATE OF NORTH DAKOTA, | ) | |
| Plaintiffs, | ) | |
| v. | ) | Civil Action No: |
| MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE, | ) | |
| Defendants. | ) | |

CONSENT DECREE

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WHEREAS, Plaintiffs, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA"), and the State of North Dakota ("State"), have filed a Complaint for injunctive relief and civil penalties pursuant to Sections 113(b)(2) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b)(2) and 7477, alleging that Defendants, Minnkota Power Cooperative ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") have undertaken construction projects at major emitting facilities in violation of the Prevention of Significant Deterioration provisions of Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, and in violation of the federally approved and enforceable North Dakota State Implementation Plan;

WHEREAS, in their Complaint, the United States and the State (collectively, "the Plaintiffs") allege, *inter alia*, that Minnkota and Square Butte (collectively, the "Settling Defendants") failed to obtain the necessary permits and install the controls necessary under the Act to reduce their sulfur dioxide ($SO_2$), nitrogen oxide ($NO_x$), and/or particulate matter (PM) emissions;

WHEREAS, the Complaint alleges claims upon which relief can be granted against the Settling Defendants under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477;

WHEREAS, the United States provided the Settling Defendants and the State with actual notice of alleged violations in accordance with Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1);

WHEREAS, the Settling Defendants assert that there may be difficulty associated with the continuous operation of Flue Gas Desulfurization Systems at the Milton R. Young Station during the extremely cold ambient air temperatures at the plant in the winter months, and the

Parties have considered these circumstances in reaching this agreement;

WHEREAS, the Settling Defendants assert that it would be very difficult to install and continuously operate certain $NO_x$ emission controls at the cyclone-fired, lignite-burning Units at the Milton R. Young Station;

WHEREAS, NDDH contemplates that, upon full implementation of the controls and other requirements of this Consent Decree, the Settling Defendants will have installed BACT-level $SO_2$ controls for purposes of netting under this Decree;

WHEREAS, the Parties have agreed that settlement of this action is in the best interest of the Parties and in the public interest, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

WHEREAS, the Parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the Settling Defendants have cooperated in the resolution of this matter;

WHEREAS, the Settling Defendants have denied and continue to deny the violations alleged in the Complaint, and nothing herein shall constitute an admission of liability; and

WHEREAS, the Parties have consented to entry of this Consent Decree without trial of any issues;

NOW, THEREFORE, without any admission of fact or law, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

## I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, the Settling Defendants waive all objections and defenses that they may have to the Court's jurisdiction over this action, to the Court's jurisdiction over the Settling Defendants, and to venue in this District. The Settling Defendants shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. For purposes of the Complaint filed by the Plaintiffs in this matter and resolved by the Consent Decree, and for purposes of entry and enforcement of this Consent Decree, the Settling Defendants waive any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the Parties to this Consent Decree. Except as provided in Section XXV (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice.

## II. APPLICABILITY

2. Except as set forth in Paragraph 3, the provisions of this Consent Decree shall, upon entry, apply to and be binding upon the Settling Defendants and their successors and assigns, and upon the Settling Defendants' officers, employees and agents solely in their capacities as such.

3. Upon entry, the provisions of this Consent Decree that relate exclusively to Unit 1 at the Milton R. Young Station shall only apply to and be binding upon Minnkota, and its

successors and assigns, and upon Minnkota's officers, employees and agents solely in their capacities as such.

4. The Settling Defendants shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, the Settling Defendants shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, the Settling Defendants shall not assert as a defense the failure of their officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

## III. DEFINITIONS

5. A "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lbs/MMBtu for the current Operating Day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-day Rolling Average Emission Rate shall include all start-up, shutdown and Malfunction periods within each Operating Day. A Malfunction shall be excluded from this Emission Rate, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree. The reference methods for determining $SO_2$ and $NO_x$ Emission Rates shall be those specified in 40 C.F.R. Part 75, Appendix F.

6. A “30-day Rolling Average Removal Efficiency” means the percent reduction in the mass of a pollutant achieved by a Unit’s pollution control device over a 30-Operating Day period. This percentage shall be calculated by subtracting the Unit’s outlet 30-day Rolling Average Emission Rate from the Unit’s inlet 30-day Rolling Average Emission Rate, dividing that difference by the Unit’s inlet 30-day Rolling Average Emission Rate, and then multiplying by 100. A new 30-day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all start-up, shutdown and Malfunction periods with each Operating Day. A Malfunction shall be excluded from this Removal Efficiency, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree. The reference method for determining both the inlet and outlet 30-day Rolling Average Emission Rate, for the purposes of calculating the $SO_2$ 30-day Rolling Average Removal Efficiency, shall be that specified in 40 C.F.R. Part 75, Appendix F.

7. “CEMS” or “Continuous Emission Monitoring System,” means, for obligations involving $NO_x$ and $SO_2$ under this Consent Decree, the devices defined in 40 C.F.R. § 72.2, and installed and maintained as required by 40 C.F.R. Part 75.

8. “Clean Air Act” or “Act” means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

9. “Consent Decree” means this Consent Decree.

10. “Emission Rate” for a given pollutant means the number of pounds of that pollutant emitted per million British thermal units of heat input (lb/MMBtu), measured in accordance with this Consent Decree.

11. “EPA” means the United States Environmental Protection Agency.

12. “ESP” means electrostatic precipitator, a pollution control device for the reduction of PM.

13. “Flue Gas Desulfurization System” or “FGD” means a pollution control device that employs flue gas desulfurization technology, including an absorber utilizing lime, flyash, or limestone slurry, for the reduction of sulfur dioxide emissions.

14. “Fossil Fuel” means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

15. “lb/MMBtu” means one pound of a pollutant per million British thermal units of heat input.

16. “Malfunction” means malfunction as that term is defined under 40 C.F.R. § 60.2 (July 1, 2004).

17. “MW” means a megawatt or one million Watts.

18. “Milton R. Young Station” means, for purposes of this Consent Decree only, the Settling Defendants’ electric generating Units near Center, North Dakota, which currently consist of two lignite-fired cyclone units. Unit 1 has a nominal net rating of 235 MW. Unit 2 has a nominal net rating of 440 MW. “Milton R. Young Station” also includes the Settling Defendants’ proposed Unit 3, with a proposed net rating of 600 MW. The Settling Defendants anticipate submitting a permit to construct application on or before June 1, 2009. Subject to NDDH’s permit to construct review process, the Unit 3 permit is anticipated to be issued by December 31, 2010, construction is expected to commence on or before December 31, 2012, and operation is expected to commence on or before December 31, 2015.

19. “NDDH” shall mean the North Dakota Department of Health.

20. "Netting" shall mean the process of determining whether a particular physical change or change in the method of operation of a major stationary source results in a net emissions increase, as that term is defined at 40 C.F.R. § 52.21(b)(3)(i) and Chapter 33-15-15 of the North Dakota Administrative Code (Feb. 1, 2005).

21. "$NO_x$" means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

22. "$NO_x$ Allowance" means an authorization or credit to emit a specified amount of $NO_x$ that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Act or a State Implementation Plan. The Parties acknowledge that at the time of lodging of this Consent Decree that no $NO_x$ Allowance program is applicable to Milton R. Young Station.

23. "$NO_x$ BACT Determination" shall mean the conclusions made by the NDDH as a result of reviewing the $NO_x$ Top-Down BACT Analysis. Such determination shall be carried out in accordance with the applicable federal and state statutes, regulations, and guidance cited in the definition of "$NO_x$ Top-Down BACT Analysis," below, and shall include the selection of control technology to be installed on Units 1 and 2 and 30-day Rolling Average Emission Rates applicable to Units 1 and 2 and to be continuously complied with by the Settling Defendants.

24. "$NO_x$ Top-Down BACT Analysis" shall mean a study prepared by the Settling Defendants to identify the emission limits required by 42 U.S.C. § 7475(a)(4) and 40 C.F.R. § 52.21(j)(3), defined by 42 U.S.C. § 7479(3) and 40 C.F.R. §52.21(b)(12), and expressed as a 30-Day Rolling Average $NO_x$ Emission Rate. The study shall be carried out in accordance with the provisions of Chapter B of EPA's "New Source Review Workshop Manual—Prevention of

Significant Deterioration and Nonattainment Area Permitting," (Draft October 1990) ("EPA's NSR Manual"). The study shall not include any other elements of PSD permitting required by other chapters of EPA's NSR Manual (notwithstanding any cross-reference in Chapter B to such other chapters), 40 C.F.R. § 52.21, or N.D. ADMIN. CODE § 33-15-15-01.2.

25. "Over-fire Air" means a technology to reduce $NO_x$ formation in a Unit boiler by directing a portion of the air to be combusted through ports above the level of the cyclones in the furnace.

26. "Operating Day" means any calendar day on which a Unit fires fossil fuel.

27. "Parties" means the United States of America, the State of North Dakota, and the Settling Defendants. "Party" means one of the four named "Parties."

28. "Plant-Wide 12-Month Rolling Average Tonnage" means the sum of the tons of the pollutant in question emitted from the Milton R. Young Station in the most recent complete month and the previous eleven (11) months. A new Plant-Wide 12-Month Rolling Average Tonnage shall be calculated for each new complete month in accordance with the provisions of this Consent Decree. The calculation of each Plant-Wide 12-Month Rolling Average Tonnage shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each calendar month, unless the Malfunction event is also deemed a "Force Majeure Event" as defined in Section XIV of this Consent Decree (Force Majeure), in which case such emissions shall be excluded.

29. "Plant-Wide Tonnage for One Calendar Year" means the sum of the tons of the pollutant in question emitted from the Milton R. Young Station in any 12-Month calendar year. A new Plant-Wide Tonnage for One Calendar Year shall be calculated for each new calendar

year. The calculation of each Plant-Wide Tonnage for One Calendar Year shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each 12-Month calendar year, unless the Malfunction event is also deemed a "Force Majeure Event" as defined in Section XIV of this Consent Decree (Force Majeure), in which case such emissions shall be excluded.

30. "Plant-Wide Tonnage for the Annual Average of Two Calendar Years" means the sum of the tons of the pollutant in question emitted from the Milton R. Young Station in any two consecutive 12-month calendar years, divided by two. A new Plant-Wide Tonnage for the Annual Average of Two Calendar Years shall be calculated for each new complete 12-month calendar year. The calculation of each Plant-Wide Tonnage for the Annual Average of Two Calendar Years shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each 12-Month calendar year, unless the Malfunction event is also deemed a "Force Majeure Event" as defined in Section XIV of this Consent Decree (Force Majeure), in which case such emissions shall be excluded.

31. "PM" means total particulate matter, measured in accordance with the provisions of this Consent Decree.

32. "PM CEMS" or "PM Continuous Emission Monitoring System" means, as specified in Section VI (PM Emission Reduction and Controls) of this Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

33. "PM Emission Rate" means the average number of pounds of PM emitted per million British thermal units of heat input ("lbs/MMBtu") from the Unit stack, as measured in an annual

stack test from the Unit stack, in accordance with the reference method set forth in 40 C.F.R. Part 60, Appendix A, Method 5 (filterable portion only) or Method 17 (filterable portion only).

34. "Prevention of Significant Deterioration" or "PSD" means the prevention of significant deterioration of air quality program under Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492, and 40 C.F.R. Part 52.

35. "Project Dollars" means the Settling Defendants' expenditures and payments incurred or made in carrying out the Projects identified in Section VIII (Additional Injunctive Relief) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII (Additional Injunctive Relief) of this Consent Decree; and (b) constitute (i) the Settling Defendants' direct payments for such projects, (ii) the Settling Defendants' external costs for contractors, vendors, and equipment, (iii) the Settling Defendants' internal costs consisting of employee time, travel, or out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with Generally Accepted Accounting Principles ("GAAP"), or (iv) the discounted present value of the cash payments made by the Settling Defendants under a contract with another entity to carry out the project.

36. "Rich Reagent Injection" means a technology that injects reagent, such as ammonia or urea, into a Unit boiler to react with and reduce $NO_x$ emissions.

37. "Selective Catalytic Reduction" means a pollution control device for reducing $NO_x$ emissions through the use of selective catalytic reduction technology.

38. "Selective Non-Catalytic Reduction" means a pollution control device for reducing $NO_x$ emissions through the use of selective non-catalytic reduction technology.

39. "Settling Defendants" means Minnkota Power Cooperative, Inc., and Square Butte Electric Cooperative.

40. "$SO_2$" means sulfur dioxide, measured in accordance with the provisions of this Consent Decree.

41. "$SO_2$ Allowance" means "allowance" of $SO_2$ as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected Unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

42. "Title V Permit" means the permit required of the Settling Defendants' major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

43. "Unit" means, for the purposes of this Consent Decree, collectively, the coal crusher, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for the production of electricity. An electric utility steam generating station may comprise one or more Units.

## IV. $SO_2$ EMISSION REDUCTIONS AND CONTROLS

### A. $SO_2$ Emission Controls

#### 1. New FGD Installations at Milton R. Young Station Unit 1

44. No later than December 31, 2010, the Settling Defendants shall elect to install either a wet FGD or a dry FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 46) at Unit 1, and shall notify the Plaintiffs in writing as to which option the Settling Defendants have elected for this Unit.

45. Beginning no later than December 31, 2011, the Settling Defendants shall install and commence continuous operation of the FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 46) elected above on Unit 1, and shall achieve and thereafter maintain:

a. If the Settling Defendants elect to install a wet FGD, a 30-Day Rolling Average Removal Efficiency for $SO_2$ at Unit 1 of at least ninety-five percent (95%), subject to the provisions of Paragraph 49;

b. If the Settling Defendants elect to install a dry FGD, a 30-Day Rolling Average Removal Efficiency for $SO_2$ at Unit 1 of at least ninety percent (90%).

46. With prior written notice to and written approval from EPA and the State, the Settling Defendants may, in lieu of installing and operating an FGD at Unit 1, install and operate an alternative $SO_2$ control technology at this Unit that achieves and maintains a 30-Day Rolling Average Removal Efficiency for $SO_2$ of at least ninety five percent (95%), unless Defendants demonstrate, and Plaintiffs agree, that the alternative control technology will provide significant additional multi-pollutant reductions, in which case Settling Defendant shall achieve and maintain a 30-Day Rolling Average Removal Efficiency for $SO_2$ of at least ninety percent (90%).

**2. <u>FGD Upgrades for Milton R. Young Station Unit 2</u>**

47. No later than December 31, 2010, the Settling Defendants shall design and upgrade the FGD on Unit 2. Beginning no later than this same date, the Settling Defendants shall also achieve and thereafter maintain a 30-Day Rolling Average Removal Efficiency for $SO_2$ at Unit 2 of at least ninety percent (90%), subject to the provisions of Paragraph 49.

### 3. Continuous Operation of $SO_2$ Controls

48. The Settling Defendants shall continuously operate each FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 46) covered under this Consent Decree at all times that the Unit it serves is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the FGDs, or equivalent technology, for minimizing emissions to the extent practicable. The Settling Defendants need not operate an FGD system during periods of Malfunction of the FGD, or during periods of Malfunction of the Unit that have a significant adverse impact on the operation of the FGD, provided that the Settling Defendants satisfy the requirements for a Malfunction as set forth in Paragraph 138 (Malfunctions). As set forth in Paragraph 138, a Malfunction may also constitute a Force Majeure Event if it meets the requirements for a Force Majeure Event in Section XIV (Force Majeure) of this Consent Decree.

### 4. Maximizing $SO_2$ Emission Reductions while Minimizing Ice Formation During Wintertime Operations of FGDs

49. In light of the potential for substantial and dangerous ice formation on emission stacks utilizing wet FGDs as a result of the particularly severe winter weather conditions in North Dakota, the Settling Defendants shall, by December 31, 2006, submit to EPA and NDDH for review and approval an evaluation of technologies and best management practices for minimizing and eliminating ice formation on the stacks while minimizing any effect on emission reductions at any Units served or to be served by a wet FGD. Such evaluation shall be performed by an independent contractor, and shall include an analysis of the feasibility, effectiveness, reliability, energy impacts, and economic costs of such technologies and best management practices. In their submittal, the Settling Defendants shall evaluate such

technologies and best management practices, and shall propose either available technologies, best management practices, or both.

a. Upon EPA's and NDDH's approval of the Settling Defendants' evaluation, EPA and NDDH shall provide the Settling Defendants with a written determination regarding an available technology and best management practices. Within 90 days after the installation or upgrade of a wet FGD pursuant to this Consent Decree, the Settling Defendants shall commence implementation of EPA's and NDDH's determination, subject to the Dispute Resolution procedures set forth in Paragraphs 139 through 146 of this Consent Decree.

b. The Settling Defendants shall include in the periodic compliance reports required pursuant to Section XI (Periodic Reporting) of this Consent Decree, a summary of the effectiveness of any technologies and best management practices in minimizing and eliminating ice formation on the stacks while minimizing any effect on emission reductions at any Units served by a wet FGD at the Milton R. Young Unit 2.

**B. <u>Tonnage Limits for $SO_2$ Emissions</u>**

50. The Settling Defendants shall comply with the following $SO_2$ emission limitations for the Milton R. Young Station:

a. Beginning January 1, 2006, the Settling Defendants shall not emit more than 31,000 tons of $SO_2$ per year based on a Plant-Wide Tonnage for the Annual Average of Two Calendar Years;

b. Beginning January 1, 2011, the Settling Defendants shall not emit more than 26,000 tons of $SO_2$ per year based on a Plant-Wide Tonnage for One Calendar Year;

c. Beginning January 1, 2012, and each year thereafter, the Settling Defendants shall not emit more than 11,500 tons of $SO_2$ per year based on a Plant-Wide Tonnage for the Annual Average of Two Calendar Years; and

d. In the event that Milton R. Young Unit 3 is not operational by December 31, 2015, then beginning January 1, 2014, and each year thereafter, the Settling Defendants shall not emit more than 8,500 tons of $SO_2$ per year based on a Plant-Wide Tonnage for the Annual Average of Two Calendar Years.

51. Beginning on the date of entry of this Consent Decree, and prior to the Settling Defendants' implementation of EPA's and NDDH's determination pursuant to Paragraph 49, above, the Settling Defendants shall continue to implement practices, to the extent practicable, to minimize and eliminate ice formation on the stacks while minimizing any effect on emission reductions at Milton R. Young Unit 2.

52. Notwithstanding the foregoing, the Settling Defendants may submit to EPA and NDDH a petition for a higher $SO_2$ emissions limitation than the 31,000 ton and 26,000 ton limits noted in Subparagraphs 50(a) and (b), above, if the Settling Defendants can demonstrate that they are unable to comply with such limitation given the energy demands of their cooperative, and despite utilization of best management practices and operation of the Milton R. Young Unit

2 FGD to minimize $SO_2$ emissions to the maximum extent practicable. EPA's and NDDH's disapproval of any such petition shall be subject to the dispute resolution provisions in Section XV (Dispute Resolution) of this Consent Decree.

53. The Settling Defendants shall not use $SO_2$ Allowances or credits to comply with the $SO_2$ emissions limitations set forth in Paragraph 50.

**C. <u>Surrender of $SO_2$ Allowances</u>**

54. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for Units 1 and 2—and from Unit 3 to the extent that $SO_2$ Allowances are allocated by EPA to that Unit – so that such $SO_2$ Allowances can never be used to meet any compliance requirement under the Clean Air Act, the North Dakota State Implementation Plan, or this Consent Decree.

55. For each year specified below, the Settling Defendants shall surrender to EPA, or transfer to a non-profit third party selected by the Settling Defendants for surrender, $SO_2$ Allowances that have been allocated to the Milton R. Young Station for the specified calendar year:

| **Calendar Year** | **Amount** |
|---|---|
| 2012-2015 | 4,346 Allowances |
| 2016-2018 | 8,693 Allowances |
| 2019 | 12,170 Allowances |
| 2020 and thereafter | 14,886 Allowances if Milton R. Young Units 1, 2, and 3 (as proposed) are operational by December 31, 2015, and 17,886 Allowances if only Milton R. Young Units 1 and 2 are operational by December 31, 2015 |

The Settling Defendants shall make such surrender annually, within forty-five (45) days of their receipt from EPA of the Annual Deduction Reports for $SO_2$. Any surrender need not include the specific $SO_2$ Allowances that were allocated to the Settling Defendants, so long as the Settling Defendants surrender $SO_2$ Allowances that are from the same year or an earlier year and that are equal to the number required to be surrendered under this Paragraph. The requirements in this Subsection (IV(C)) of the Consent Decree pertaining to the Settling Defendants' use and retirement of $SO_2$ Allowances are permanent injunctions not subject to any termination provision of this Decree.

56. If any $SO_2$ Allowances are transferred directly to a non-profit third party, the Settling Defendants shall include a description of such transfer in the next report submitted to EPA and NDDH pursuant to Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the $SO_2$ Allowances and a listing of the serial numbers of the transferred $SO_2$ Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the $SO_2$ Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any $SO_2$ Allowances, the Settling Defendants shall include a statement that the third-party recipient(s) surrendered the $SO_2$ Allowances for permanent surrender to EPA in accordance with the provisions of Paragraphs 54 and 55 within one (1) year after the Settling Defendants transferred the $SO_2$ Allowances to them. The Settling Defendants shall not have complied with the $SO_2$ Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred $SO_2$ Allowances to EPA.

57. For all $SO_2$ Allowances surrendered to EPA, the Settling Defendants or the third-party recipient(s) (as the case may be) shall first submit an $SO_2$ Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such $SO_2$ Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, the Settling Defendants or the third-party recipient(s) shall irrevocably authorize the transfer of these $SO_2$ Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the $SO_2$ Allowances being surrendered.

**D. <u>General $SO_2$ Provisions</u>**

58. In determining Emission Rates for $SO_2$, the Settling Defendants shall use CEMS in accordance with those reference methods specified in 40 C.F.R. Part 75.

59. For the purpose of calculating the 30-Day Rolling Average Removal Efficiency, the outlet $SO_2$ Emission Rate and the inlet $SO_2$ Emission Rate shall be determined based on the data generated in accordance with 40 C.F.R. Part 75 (using $SO_2$ CEMS data from both the inlet and outlet of the control device).

60. If any Unit subject to this Consent Decree is constructed to allow any flue gas to by-pass the $SO_2$ pollution control equipment, the outlet 30-Day Rolling Average Emission Rate shall be determined from $SO_2$ CEMS located after the by-pass return, and the inlet 30-Day Rolling Average Emission Rate shall be determined from $SO_2$ CEMS located before the by-pass.

## V. NOx EMISSION REDUCTIONS AND CONTROLS

### A. Phase I $NO_x$ Emissions Reductions and Controls

61. No later than December 31, 2007, the Settling Defendants shall install and commence continuous operation of Over-fire Air on Unit 2 at the Milton R. Young Station.

62. No later than December 31, 2009, the Settling Defendants shall install and commence continuous operation of Over-fire Air on Unit 1 at the Milton R. Young Station.

63. With prior written notice to and written approval from EPA and NDDH, the Settling Defendants may, in lieu of installing and operating the $NO_x$ controls required by Paragraphs 61 or 62, install and operate equivalent technology that will achieve a $NO_x$ emission rate of no greater than 0.36 lb/MMBtu based on a 30-Day Rolling Average Emission Rate.

### B. Phase II $NO_x$ Emissions Reductions and Controls

64. The Phase II 30-Day Rolling Average $NO_x$ Emission Rates shall be determined in accordance with the procedures set forth in this subsection.

65. Within six months after entry of this Consent Decree, the Settling Defendants shall submit to NDDH for review and approval, and to EPA for review, a $NO_x$ Top-Down BACT Analysis for each existing coal-fired Unit at the Milton R. Young Station. The Settling Defendants' $NO_x$ Top-Down BACT Analysis shall include all information necessary for NDDH to make a BACT Determination, and any additional information requested by EPA and NDDH. The Settling Defendants' $NO_x$ Top-Down BACT Analysis shall include an evaluation of Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Over-fire Air, and Rich Reagent Injection, as well as other $NO_x$ control technologies. This $NO_x$ Top-Down BACT Analysis is independent and separate from the Settling Defendants' plans to install one or more

technologies pursuant to Paragraphs 61 and 62. The Settling Defendants shall retain a qualified contractor to assist in the performance and completion of each $NO_x$ Top-Down BACT Analysis.

66. NDDH shall review the Settling Defendants' $NO_x$ Top-Down BACT Analysis, and shall develop its BACT Determination, in accordance with applicable federal and state statues, regulations, and guidance, including those cited in the definition of a $NO_x$ Top-Down BACT Analysis under this Consent Decree. After consultation with EPA, NDDH shall provide to the Parties its BACT Determination for $NO_x$ emissions from each existing coal-fired Unit at the Milton R. Young Station. NDDH's BACT Determination shall include for each Unit the specific control technologies to be installed and a specific Phase II 30-Day Rolling Average $NO_x$ Emission Rate limitation (lbs/MMBtu). NDDH's BACT Determination shall also address specific $NO_x$ emission limitations during Unit startups. NDDH's BACT Determination shall be subject to the Dispute Resolution procedures set forth in Paragraph 147 of this Consent Decree.

67. Beginning no later than December 31, 2010, the Settling Defendants shall achieve and maintain the Phase II 30-Day Rolling Average $NO_x$ Emission Rates established by NDDH through its $NO_x$ BACT Determination for Unit 2. Beginning no later than December 31, 2011, the Settling Defendants shall achieve and maintain the Phase II 30-Day Rolling Average $NO_x$ Emission Rates established by NDDH through its $NO_x$ BACT Determination for Unit 1. Such Phase II 30-Day Rolling Average $NO_x$ Emission Rates shall not affect the Settling Defendants' obligation to also comply with the Phase I 30-Day Rolling Average $NO_x$ Emission Rates set forth herein.

**C. <u>Use of $NO_x$ Allowances</u>**

68. Except as provided in this Consent Decree, the Settling Defendants shall not sell or

trade any surplus $NO_x$ Allowances allocated to Units 1, 2, and 3 at the Milton R. Young Station that would otherwise be available for sale or trade as a result of the actions taken by the Settling Defendants to comply with the requirements of this Consent Decree.

69. The number of $NO_x$ Allowances that are surplus to the Settling Defendants' $NO_x$ Allowance-holding requirements shall be equal to the amount by which the $NO_x$ Allowances allocated to the Settling Defendants' Units 1, 2, and 3 at the Milton R. Young Station for a particular year are greater than the total amount of $NO_x$ emissions from those same Units for the same year.

70. Provided that the Settling Defendants are in compliance with the $NO_x$ emission limitations of this Consent Decree, nothing in this Consent Decree shall preclude the Settling Defendants from selling or transferring $NO_x$ Allowances allocated to the Milton R. Young Station that become available for sale or trade as a result of:

a. activities that reduce $NO_x$ emissions from any Unit at the Milton R. Young Station prior to the date of entry of this Consent Decree;

b. the installation and operation of any $NO_x$ pollution control technology or technique that is not otherwise required under this Consent Decree;

c. achievement and maintenance of $NO_x$ emission rates below the emission limits required by Section V ($NO_x$ Emissions Reductions and Controls);

d. permanent shutdown of any Unit at the Milton R. Young Stations not otherwise required by this Consent Decree; and

e. other emission reduction measures that are agreed to by the Parties and made enforceable through modifications of this Consent Decree;

so long as the Settling Defendants timely report the generation of such surplus $NO_x$ Allowances in accordance with Section XI (Periodic Reporting) of this Consent Decree. The Settling Defendants shall be allowed to sell or transfer $NO_x$ Allowances equal to the $NO_x$ emissions reductions achieved for any given year by any of the actions specified in Subparagraphs (b) through (e) only to the extent that the total $NO_x$ emissions from all Units at the Milton R. Young Station are below the emissions limits required by this Consent Decree.

71. The Settling Defendants may not purchase or otherwise obtain $NO_x$ Allowances from another source for purposes of complying with the requirements of this Consent Decree. However, nothing in this Consent Decree shall prevent the Settling Defendants from purchasing or otherwise obtaining $NO_x$ Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

**D. <u>General $NO_x$ Provisions</u>**

72. In determining Emission Rates for $NO_x$, the Settling Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75.

73. At any time following the commencement of operation of the specific $NO_x$ control technologies required by the NDDH's $NO_x$ BACT Determination, the Settling Defendants may petition the Plaintiffs to revise the applicable Phase II 30-Day Rolling Average Emission Rate for $NO_x$. In their petition, the Settling Defendants shall demonstrate and explain why they cannot consistently achieve and maintain the 30-Day Rolling Average Emission $NO_x$ Rate required by the NDDH's $NO_x$ BACT Determination for the Unit in question, considering all relevant information. The Settling Defendants shall include in such petition a proposed

alternative 30-Day Rolling Average Emission Rate for $NO_x$. The Settling Defendants shall also retain a qualified contractor to assist in the preparation and completion of the petition for an alternative 30-Day Rolling Average Emission Rate for $NO_x$. The Settling Defendants shall provide with each petition all pertinent documents and data. If the Plaintiffs disapprove the alternative 30-Day Rolling Average Emission Rate for $NO_x$ proposed by the Settling Defendants, such disapproval shall be subject to the provisions of Section XV (Dispute Resolution) of this Consent Decree. The Settling Defendants shall submit any petition for any Unit under this Paragraph no later than six (6) months after the final compliance date specified for that Unit in Paragraph 67.

74. The Settling Defendants shall continuously operate all $NO_x$ control technology installed on the Milton R. Young Units at all times that the Unit served is in operation, consistent with the technological limitations, manufacturers' specifications to the extent practicable, and good engineering and maintenance practices for the $NO_x$ control technology. The Settling Defendants need not operate $NO_x$ control technology during periods of Malfunction of the $NO_x$ control technology, or during periods of Malfunction of the Unit that have a significant adverse impact on the operation of the $NO_x$ control technology, provided that the Settling Defendants satisfy the requirements for Malfunction Events as set forth in Paragraph 138 (Malfunction Events). As set forth in Paragraph 138, a Malfunction may also constitute a Force Majeure Event if it meets the requirements for a Force Majeure Event in Section XIV (Force Majeure) of this Consent Decree.

## VI. PM EMISSION REDUCTIONS AND CONTROLS

### A. Optimization of PM Emission Controls

75. Within ninety (90) days after entry of this Consent Decree and continuing thereafter, the Settling Defendants shall continuously operate each PM Control Device on the Milton R. Young Station Units to maximize PM emission reductions, consistent with the operational and maintenance limitations of the units. Specifically, the Settling Defendants shall, at a minimum: (a) energize each section of the ESP for each Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESP for each Unit to achieve the greatest possible removal of PM; (c) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; (d) inspect for, and schedule for repair, any openings in ESP casings and ductwork to minimize air leakage; (e) optimize for Unit 1 the plate-cleaning and discharge-electrode cleaning systems for the ESP by varying the cycle time, cycle frequency, rapper-vibrator intensity, and number of strikes per cleaning event; and (f) optimize for Unit 2 the plate-cleaning system for the ESP by varying the cycle time and frequency of the cycle.

**B. <u>Compliance with PM Emission Limits</u>**

76. Within one year of entry of the Consent Decree, and continuing annually thereafter, the Settling Defendants shall demonstrate, in accordance with Paragraphs 80 and 81, that Unit 2 at the Milton R. Young Station can achieve and thereafter maintain a PM Emission Rate of no greater than 0.030 lb/MMBtu.

77. No later than one-hundred-eighty (180) days after the Settling Defendants install and commence continuous operation of the FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 46) on Unit 1 at the Milton R. Young Station, and continuing annually thereafter, the Settling Defendants shall demonstrate, in accordance with Paragraphs 80 and 81,

that Unit 1 at the Milton R. Young Station can achieve and thereafter maintain a PM Emission Rate of:

a. No greater than 0.030 lb/MMBtu if the Settling Defendants install a wet FGD; and

b. No greater than 0.015 lb/MMBtu if the Settling Defendants install a dry FGD.

78. The Settling Defendants shall continuously operate each ESP or baghouse at the Milton R. Young Station at all times that each Unit the ESP or baghouse serves is combusting Fossil Fuel, consistent with good engineering practices for PM control, to minimize PM emissions to the extent practicable. The Settling Defendants need not operate an ESP or baghouse during periods of Malfunction of the ESP or baghouse, or during periods of Malfunction of the Unit that have a significant adverse impact on the operation of the ESP or baghouse, provided that the Settling Defendants satisfy the requirements for Malfunction Events as set forth in Paragraph 138 (Malfunction Events). As set forth in Paragraph 138, a Malfunction may also constitute a Force Majeure Event if it meets the requirements for a Force Majeure Event in Section XIV (Force Majeure) of this Consent Decree.

79. Within 180 days after the Settling Defendants complete the installation of any equipment required by Paragraphs 76 and 77, the Settling Defendants shall conduct a performance test demonstration to ensure that the PM emission limitation set forth in Paragraphs 76 and 77 can be consistently achieved in practice, including all requirements pertaining to proper operation and maintenance of control equipment. If the performance demonstration shows that the control equipment cannot consistently meet the required PM emission limitation, the Settling Defendants shall submit a report to EPA and NDDH proposing alternative emission

limits.

### C. PM Monitoring

#### 1. PM Stack Tests

80. Beginning in calendar year 2006, and continuing annually thereafter, the Settling Defendants shall conduct PM performance testing on Milton R. Young Station Units 1 and 2. Such annual performance tests may be satisfied by stack tests conducted in a given year, in accordance with the Settling Defendants' permit from the State of North Dakota.

81. In determining the PM Emission Rate, the Settling Defendants shall use the reference methods specified in 40 C.F.R. Part 60, App. A, Method 5 (filterable portion only) or 40 C.F.R. Part 60, App. A, Method 17 (filterable portion only), using stack tests, or alternative methods that are requested by the Settling Defendants and approved by EPA. The Settling Defendants shall also calculate the PM Emission Rates from annual stack tests in accordance with 40 C.F.R. § 60.8(f). In addition, the Settling Defendants shall submit the results of each PM stack test to NDDH and EPA within forty-five (45) days of completion of each test.

#### 2. PM CEMS

82. The Settling Defendants shall install and operate PM CEMS in accordance with Paragraphs 82 through 88 on Unit 2 at the Milton R. Young Station. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/MMBtu. The Settling Defendants shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in lb/MMBtu. The Settling Defendants shall use reasonable efforts to keep the PM CEMS running and producing data whenever Unit 2 is

operating.

83. No later than six (6) months after entry of this Consent Decree, the Settling Defendants shall submit to EPA and NDDH for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a plan for the installation and certification of the PM CEMS for Milton R. Young Unit 2.

84. No later than one hundred twenty (120) days prior to the deadline to commence operation of the PM CEMS, the Settling Defendants shall submit to EPA and NDDH for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. Following EPA and NDDH's approval of the protocol, the Settling Defendants shall thereafter operate the PM CEMS in accordance with the approved protocol.

85. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, the Settling Defendants shall use the criteria set forth in EPA's Amendments to Standards of Performance for New Stationary Sources: Monitoring Requirements, 69 Fed. Reg. 1786 (January 12, 2004).

86. The Settling Defendants shall install and commence operation of PM CEMS on or before June 30, 2008.

87. By December 31, 2008, the Settling Defendants shall conduct tests and demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA and NDDH in accordance with Paragraphs 83 and 84.

88. The Settling Defendants shall operate continuous opacity monitors on Unit 1 and

Unit 2 of the Milton R. Young Station at all times those units are in operation. However, if the Settling Defendants demonstrate that either one of these continuous opacity monitors cannot provide accurate opacity measurement due to the formation of liquid water droplets in the flue gas of a stack with a wet FGD, in accordance with Question 5.6, Part 75 of EPA's Emission Monitoring Policy Manual, then the Settling Defendants may submit to EPA and NDDH for review and approval alternative opacity procedures and requirements pursuant to the provisions of 40 C.F.R. § 60.13(i)(1).

## VII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

89. Emission reductions generated by the Settling Defendants to comply with the requirements of this Consent Decree shall not be considered as a creditable emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs. Notwithstanding the preceding sentence, the Settling Defendants may use any emission decreases of $NO_x$, $SO_2$, and PM generated under this Consent Decree at Units 1 and 2 as creditable decreases for the purpose of obtaining netting credit for these pollutants at Unit 3 under the Clean Air Act's Nonattainment NSR and PSD programs, if:

a. The Settling Defendants submit, as and addendum to its construction permit application for Unit 3, an analysis that proposes emissions limits for $NO_x$, $SO_2$, and PM that are equivalent to BACT as defined in the 42 U.S.C. § 7479(3), and NDDH issues a federally enforceable permit for Unit 3 that includes emissions limits that reflect BACT-equivalent level controls at the time of construction of the Unit, and that are at least as stringent as a 30-Day Rolling Average $SO_2$

Removal Efficiency of at least ninety-five percent 95% (if the Settling Defendants install a wet FGD on Unit 3) or 90% (if the Settling Defendants install a dry FGD on Unit 3), a 30-Day Rolling Average $NO_x$ Emission Rate not greater than 0.100 lb/MMBtu, and an Emission Rate for PM of no greater than 0.015 lbs/MMBtu, provided that, at any time following the commencement of operation of this new Unit, the Settling Defendants may submit to EPA and NDDH a written petition for a higher 30-Day Rolling Average $NO_x$ Emission Rate if the Settling Defendants can demonstrate that it cannot achieve such an emission rate on this new Unit;

b. The Settling Defendants have been and remain in full compliance with the plant-wide $SO_2$ tonnage limitation set forth in Paragraph 50 of this Consent Decree and NDDH has issued a federally-enforceable permit for Units 1, 2, and 3 that will limit the Plant-Wide Annual Average of the Tonnage for Two Calendar Years for $SO_2$ at those units to 11,500 tons per year commencing January 1, 2012; and

c. NDDH determines through air quality modeling submitted by the Settling Defendants in accordance with NDDH modeling protocols that the impact on either a PSD increment or on visibility in Class I Areas from the combined emissions at Units 1, 2 and 3, after the pollution control upgrades and installations required by this Consent Decree are operational, will be less than the impact from the combined emissions at Units 1 and 2 before such controls are operational.

90. Decreases in actual emissions of $NO_x$, $SO_2$, and PM generated under this Consent Decree at Units 1 and 2 qualify as contemporaneous decreases under 40 C.F.R. § 52.21(b)(3)(ii)

(July 1, 2005) for the purpose of obtaining netting credits for these pollutants at Unit 3, as long as the Settling Defendants commence construction of Unit 3 on or before December 31, 2012.

91. Nothing in this Consent Decree is intended to affect the application of Section 33-15-15-01.2 of the North Dakota Administrative Code regarding the availability of extensions on the commencement of construction for newly permitted facilities.

92. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by NDDH and EPA as creditable emission decreases for the purpose of attainment demonstrations submitted pursuant to Section 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS or PSD increment.

## VIII. ADDITIONAL INJUNCTIVE RELIEF

93. The Settling Defendants shall implement the wind turbine project ("Project") described in this Section in compliance with the approved plans and schedules for such Project and other terms of this Consent Decree. The Settling Defendants shall submit plans for the Project to the United States for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree in accordance with the schedules set forth in this Section. In implementing the Project, the Settling Defendants shall spend no less than $5.0 million in funds ("Project Dollars") pursuant to the schedule set forth in Paragraph 103. The Settling Defendants shall maintain, and present to the United States, upon request, all documents to substantiate the Project Dollars expended and shall provide these documents to the United States and NDDH within thirty (30) days of a request by the United States or NDDH for the documents.

94. The Settling Defendants shall make all plans and reports prepared by the Settling

Defendants pursuant to the requirements of this Section of the Consent Decree publicly available without charge.

95. The Settling Defendants shall certify, as part of the plan submitted to the United States for the Project that, as of the date of this Consent Decree, the Settling Defendants are not otherwise required by law to perform the Project described in the plan, that the Settling Defendants are unaware of any other person who is required by law to perform the Project, and that the Settling Defendants will not use the Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law.

96. The Settling Defendants shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

97. Regardless of whether the Settling Defendants elected (where such election is allowed) to undertake the Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, the Settling Defendants acknowledge that they will receive credit for the expenditure of such funds as Project Dollars only if the Settling Defendants demonstrate that the funds have been actually spent by either the Settling Defendants or by the person or instrumentality receiving them (or, in the case of internal costs, have actually been incurred by the Settling Defendants), and that such expenditures met all requirements of this Consent Decree.

98. The Settling Defendants shall receive full credit for their expenditures only to the extent that they do not receive an offsetting financial or economic benefit from such expenditures; in determining how many Project Dollars have been spent by the Settling

Defendants, the Settling Defendants shall debit any such offsetting financial or economic benefit received against any of the Settling Defendants' expenditures for the Project.

99. Within sixty (60) days following the completion of the Project required under this Consent Decree, the Settling Defendants shall submit to the United States a report that documents the date that the Project was completed, the Settling Defendants' results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by the Settling Defendants in implementing the Project.

100. The Settling Defendants shall not financially benefit to a greater extent than any other member of the general public from the sale or transfer of technology obtained in the course of implementing any Project.

101. Project Dollar credit given for the Project shall reflect the Settling Defendants' net cost in implementing the Project, and any economic benefit or income resulting from the Project shall be deducted from the Project Dollar credit given to the Project.

102. Beginning one (1) year after entry of this Consent Decree, the Settling Defendants shall provide the United States with semi-annual updates concerning the progress of the Project.

103. Within 180 days after entry of this Consent Decree, the Settling Defendants shall submit a plan to EPA and the State for a Project to provide their members with electricity generated from wind turbines. The Project shall require the Settling Defendants to either (a) by December 31, 2012, spend no less than $5,000,000 in Project Dollars to purchase and install its own wind turbines, or (b) by December 31, 2009, enter into a power purchase agreement with a provider of wind energy that requires the provider of wind energy to build new wind turbines by

this same date in the Settling Defendants' service territory with a capacity of approximately 5 MW, and that obligates the Settling Defendants to purchase the entire electric output from the turbines for a period of no less than 15 years. The power purchase agreement shall have a discounted present value of cash outflows of no less than $5,000,000, based on a discount rate of 6.25%.

## IX. CIVIL PENALTY

104. Within thirty (30) calendar days after entry of this Consent Decree, the Settling Defendants shall pay to the United States a civil penalty in the amount of $425,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2006V0009 and DOJ Case Number 90-5-2-1-07717 and the civil action case name and case number of this action. The costs of such EFT shall be the Settling Defendants' responsibility. Payment shall be made in accordance with instructions provided to the Settling Defendants by the Financial Litigation Unit of the U.S. Attorney's Office for the District of North Dakota. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, the Settling Defendants shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and case number, to the Department of Justice and to EPA in accordance with Section XVIII (Notices) of this Consent Decree.

105. Within thirty (30) calendar days after entry of this Consent Decree, the Settling Defendants shall pay to the State a civil penalty in the amount of $425,000. Payment shall be made in the form of a certified check or cashier's check, and be payable to "North Dakota Department of Health" Payment shall be sent to the Director, Air Quality Division, North

Dakota Department of Health, Bismark, North Dakota 58506-5520. To ensure proper credit, the check must reference *United States, et al. v. Minnkota Power Cooperative, et al.*, and the civil action case number.

106. Failure to timely pay the civil penalty shall subject the Settling Defendants to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render the Settling Defendants liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

107. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

## X. RESOLUTION OF CLAIMS

### A. Resolution of Plaintiffs' Civil Claims

108. **Claims Based on Modifications Occurring Before the Lodging of Consent Decree.** Entry of this Consent Decree shall resolve all civil claims of the Plaintiffs under:

a. Parts C and D of Subchapter I of the Clean Air Act;

b. Section 111 of the Clean Air Act and 40 C.F.R. Part 60;

c. Sections 502(a) and 504(a) of the Clean Air Act, but only to the extent that such claims are based on the Settling Defendants' failure to obtain an operating permit that reflects applicable requirements imposed under Part C of Subchapter I of the Clean Air Act; and

d. Chapters 33-15-12 and 33-15-15 of the North Dakota Administrative Code, as

well as Chapters 33-15-01 and 33-15-14 as they relate to Chapters 33-15-12 and 33-15-15, and all relevant prior versions of these regulations;

that arose from any modification that commenced at the Milton R. Young Station prior to the date of lodging of this Consent Decree, including but not limited to modifications alleged in the Complaint filed by the Plaintiffs in this civil action.

109. **Claims Based on Modifications After the Lodging of Consent Decree.** Entry of this Decree also shall resolve all civil claims of the Plaintiffs for pollutants regulated under:

a. Parts C and D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder as of the date of lodging of this Decree; and

b. Chapter 33-15-15 of the North Dakota Administrative Code, as well as Chapter 33-15-01 and 33-15-14 as they relate to Chapter 33-15-15;

where such claims are based on a modification completed before December 31, 2015 and: i) commenced at either Unit 1 or Unit 2 at the Milton R. Young Station after lodging of this Decree; or ii) that this Consent Decree expressly directs the Settling Defendants to undertake. The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

110. Reopener. The resolution of the civil claims of the United States provided by this Subsection is subject to the provisions of Section B of this Section.

**B. Pursuit of Plaintiffs' Civil Claims Otherwise Resolved**

111. **Bases for Pursuing Resolved Claims.** If the Settling Defendants:

a. fail by more than ninety (90) days (which may be extended by written agreement of the Parties) to complete installation or upgrade, and

commence operation, of any emission control device, unless that failure is excused under the Force Majeure provisions of this Consent Decree; or

b. emit more $SO_2$ than allowed by the following tonnage limitations:

1. 31,000 tons of $SO_2$ based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2006;

2. 26,000 tons of $SO_2$ based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2011;

3. 11,500 tons of $SO_2$ based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2012; and

4. 8,500 tons of $SO_2$ per year based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2014, in the event that Milton R. Young Unit 3 is not operational by December 31, 2015;

then the Plaintiffs may pursue any claim that is otherwise covered by the covenant not to sue or to bring administrative action under Subsection A of this Section for any claims based on modifications undertaken at a Unit where the modification(s) on which such claim is based was commenced after lodging of the Consent Decree and within the five years preceding the violation or failure specified in this Paragraph.

112. **Additional Bases for Pursuing Resolved Claims for Modifications.** The Plaintiffs may also pursue claims arising from a modification (or collection of modifications) at a Unit that is otherwise covered by the covenant not to sue or to bring administrative action under Subsection A of this Section, if the modification (or collection of modifications) at the Unit on

which such claims are based (a) was commenced after lodging of this Consent Decree, and (b) individually (or collectively) increased the maximum hourly emission rate of that Unit for $NO_x$ or $SO_2$ (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

## XI. PERIODIC REPORTING

113. Beginning thirty (30) days after the end of the first full calendar quarter following the entry of this Consent Decree, continuing on a semi-annual basis until December 31, 2020, and in addition to any other express reporting requirement in this Consent Decree, the Settling Defendants shall submit to EPA and the State a progress report, containing

a. all information necessary to determine compliance with this Consent Decree, including but not limited to information required to be included in the reports pursuant to Paragraphs 49, 55, 56, 70, and 99**;** and

b. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by the Settling Defendants to mitigate such delay.

114. In any periodic progress report submitted pursuant to this Section, the Settling Defendants may incorporate by reference information previously submitted under their Title V permitting requirements, provided that the Settling Defendants attach the Title V permit report (or pertinent portions of such report) and provide a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

115. In addition to the progress reports required pursuant to this Section, the Settling Defendants shall provide a written report to Plaintiffs of any violation of the requirements of this

Consent Decree, including exceedances of the 30-Day Rolling Average Removal Efficiencies, 30-day Rolling Average Emission Rates, PM Emission Rates, and Plant-Wide Tonnage limits within ten (10) business days of when the Settling Defendants knew or should have known of any such violation. In this report, the Settling Defendants shall explain the cause or causes of the violation and all measures taken or to be taken by the Settling Defendants to prevent such violations in the future. Exceedances of the PM Emission Rates shall be reported within forty-five (45) days of the completion of the stack test that demonstrates such non-compliance. In this report, the Settling Defendants shall explain the cause or causes of the violation and all measures taken or to be taken by the Settling Defendants to prevent such violations in the future.

116. Each Settling Defendant's report shall be signed by each of the Settling Defendant's Environmental Manager or, in his or her absence, the Settling Defendant's Vice President of Generation, or higher ranking official, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

## XII. REVIEW AND APPROVAL OF SUBMITTALS

117. The Settling Defendants shall submit each plan, report, or other submission to EPA and the State whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA and the State, to the extent that this Consent Decree provides for joint approval with the State, may approve the submittal or decline to approve it and provide written comments. Within sixty (60) days of receiving written comments from EPA, the Settling Defendants shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal for final approval to EPA and, if applicable, to the State; or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XV (Dispute Resolution) of this Consent Decree.

118. Upon receipt of EPA's final approval of the submittal, and the State's final approval, if applicable, or upon completion of the submittal pursuant to dispute resolution, the Settling Defendants shall implement the approved submittal in accordance with the schedule specified therein.

## XIII. STIPULATED PENALTIES

119. For any failure by the Settling Defendants to comply with the terms of this Consent Decree, and subject to the provisions of Sections XIV (Force Majeure) and XV (Dispute Resolution) of this Consent Decree, the Settling Defendants shall pay, within thirty (30) days after receipt of written demand to the Settling Defendants by the United States, the following stipulated penalties to the United States**:**

| **Consent Decree Violation** | **Stipulated Penalty (Per day per violation, unless otherwise specified)** |
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|---|---|
| a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree | $10,000 |
| b. Failure to comply with any applicable $NO_x$ emission rate resulting from the State's BACT determination, 30-Day Rolling Average Removal Efficiency for $SO_2$, or Emission Rate for PM, where the violation is less than 5% in excess of the limits set forth in this Consent Decree | $2,500 |
| c. Failure to comply with any applicable $NO_x$ emission rate or removal efficiency resulting from the State's BACT determination, 30-Day Rolling Average Removal Efficiency for $SO_2$, or Emission Rate for PM, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree | $5,000 |
| d. Failure to comply with any applicable $NO_x$ emission rate or removal efficiency resulting from the State's BACT determination, 30-Day Rolling Average Removal Efficiency for $SO_2$, or Emission Rate for PM, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree | $10,000 |
| e. Failure to comply with the Plant-Wide Tonnage Limitations for One Calendar Year or the Plant-Wide Tonnage Limitations for the Annual Average of Two Calendar Years | $60,000 per ton per year for the first 100 tons over the limit, and $120,000 per ton per year for each additional ton over the limit |
| f. Failure to install, upgrade, commence operation, or continue operation of the $NO_x$, $SO_2$, and PM pollution control devices on any Unit | $10,000 during the first 30 days, $27,000 thereafter |
| g. Failure to install or operate CEMS as required in Paragraphs 82 through 88 | $1,000 |
| h. Failure to conduct annual performance tests of PM emissions, as required by Paragraphs 80 and 81 | $1,000 |
| i. Failure to apply for any permit required by this Consent Decree | $1,000 |

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|---|---|
| j. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree | $750 during the first ten days, $1,000 thereafter |
| k. Using, selling, or transferring $SO_2$ Allowances, except as permitted in this Consent Decree | the surrender, pursuant to the procedures set forth in Paragraphs 55 through 57 of this Consent Decree, of $SO_2$ Allowances in an amount equal to four times the number of $SO_2$ Allowances used, sold, or transferred in violation of this Consent Decree |
| l. Using, selling or transferring $NO_x$ Allowances except as permitted in Paragraphs 68 through 71 | the surrender of $NO_x$ Allowances in an amount equal to four times the number of $NO_x$ Allowances used, sold, or transferred in violation of this Consent Decree |
| m. Failure to surrender an $SO_2$ Allowance as required by Subsection B (Surrender of $SO_2$ Allowances) of Section IV **(**$SO_2$ Emission Reductions and Controls) | (a) $27,500 plus (b) $1,000 per $SO_2$ Allowance |
| n. Failure to undertake and complete any of the Projects in compliance with Section VIII (Additional Injunctive Relief) of this Consent Decree | $1,000 during the first 30 days, $5,000 thereafter |
| o. Any other violation of this Consent Decree | $1,000 |

120. Notwithstanding the foregoing, the Settling Defendants shall not be liable for failure to comply with a 30-Day Rolling Average Removal Efficiency for $SO_2$ if the Settling Defendants are in full compliance with the requirements of Paragraph 49 of this Consent Decree, such exceedance is due to the Settling Defendants' efforts to reduce ice formation on a wet FGD stack by resorting to a partial bypass of their FGD, and the Settling Defendants maintain a 30-Day Rolling Average Removal Efficiency for $SO_2$ of no less than 83% during such periods of

partial bypass.

121. Violation of an Emission Rate or removal efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based.

122. Where a violation of a 30-Day Rolling Average Removal Efficiency (from the same source) recurs within periods of less than thirty (30) days, the Settling Defendants shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

123. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

124. The Settling Defendants shall pay all stipulated penalties to the Plaintiffs within thirty (30) days of receipt of written demand to the Settling Defendants from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless the Settling Defendants elects within 20 days of receipt of written demand to the Settling Defendants from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

125. Stipulated penalties shall continue to accrue as provided in Paragraph 119 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid

until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, the Settling Defendants shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with accrued interest, except as provided in Subparagraph (c);

c. If the Court's decision is appealed by any Party, the Settling Defendants shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with accrued interest.

For purposes of this Paragraph, the accrued stipulated penalties agreed by the Parties, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 119. The Settling Defendants need not pay any stipulated penalties based on violations which they dispute and ultimately prevail under the Dispute Resolution provisions of this Consent Decree.

126. All stipulated penalties shall be paid in the manner set forth in Section IX (Civil Penalty) of this Consent Decree.

127. Should the Settling Defendants fail to pay stipulated penalties in compliance with

the terms of this Consent Decree, the Plaintiffs shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

128. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to any Plaintiff by reason of the Settling Defendants' failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated penalty, the Settling Defendants shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

## XIV. FORCE MAJEURE

129. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of the Settling Defendants, their contractors, or any entity controlled by the Settling Defendants that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite the Settling Defendants' best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

130. **Notice of Force Majeure Events.** If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which the Settling Defendants intends to assert a claim of Force Majeure, the Settling Defendants shall notify the United States and the State in writing as soon as practicable, but in no event later than fourteen (14) business days following the date the Settling Defendants

first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, the Settling Defendants shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by the Settling Defendants to prevent or minimize the delay or violation, the schedule by which the Settling Defendants proposes to implement those measures, and the Settling Defendants' rationale for attributing a delay or violation to a Force Majeure Event. The Settling Defendants shall adopt all reasonable measures to avoid or minimize such delays or violations. The Settling Defendants shall be deemed to know of any circumstance which the Settling Defendants, their contractors, or any entity controlled by the Settling Defendants knew or should have known.

131. **Failure to Give Notice**. If the Settling Defendants fails to comply with the notice requirements in the preceding Paragraph, the Plaintiffs may void the Settling Defendants' claim for Force Majeure as to the specific event for which the Settling Defendants have failed to comply with such notice requirement.

132. **Plaintiffs' Response.** The Plaintiffs shall notify the Settling Defendants in writing regarding the Settling Defendants' claim of Force Majeure within twenty (20) business days of receipt of the notice provided under Paragraph 130. If the Plaintiffs agree that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXII (Modification) of this Consent Decree.

133. **Disagreement.** If the Plaintiffs do not accept the Settling Defendants' claim of Force Majeure, or if the Parties cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XV (Dispute Resolution) of this Consent Decree.

134. **Burden of Proof.** In any dispute regarding Force Majeure, the Settling Defendants shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. The Settling Defendants shall also bear the burden of proving that the Settling Defendants gave the notice required by Paragraph 130 and the burden of proving the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

135. **Events Excluded.** Unanticipated or increased costs or expenses associated with the performance of the Settling Defendants' obligations under this Consent Decree shall not constitute a Force Majeure Event.

136. **Potential Force Majeure Events**. The Parties agree that, depending upon the circumstances related to an event and the Settling Defendants' response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; acts of God; acts of war or terrorism; and orders by a government official, government agency, or other regulatory body acting under and authorized by applicable law that directs the Settling Defendants to supply electricity in response to a

system-wide (state-wide or regional) emergency. Depending upon the circumstances and the Settling Defendants' response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of the Settling Defendants and the Settling Defendants have taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority, provided that the Settling Defendants shall not be precluded from asserting that a new Force Majeure Event has caused or may cause a new or additional delay in complying with the extended or modified schedule.

137. As part of the resolution of any matter submitted to this Court under Section XV (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States and the State or approved by the Court. The Settling Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule.

138. **Malfunctions.** The Settling Defendants shall notify EPA and NDDH in writing of each Malfunction impacting a pollution control technology required by this Consent Decree as soon as practicable, but in no event later than fourteen (14) business days following the date that the Settling Defendants first knew, or by the exercise of due diligence should have known, of the

Malfunction. The Settling Defendants shall be deemed to know of any circumstance which the Settling Defendants, their contractors, or any entity controlled by the Settling Defendants knew or should have known. In this notice, the Settling Defendants shall describe the anticipated length of time that the Malfunction may persist, the cause or causes of the Malfunction, all measures taken or to be taken by the Settling Defendants to minimize the duration of the Malfunction, and the schedule by which the Settling Defendants proposes to implement those measures. The Settling Defendants shall adopt all reasonable measures to minimize the duration of such Malfunctions and, consistent with 40 C.F.R. § 60.11(d), shall, to the extent practicable, maintain and operate any affected Unit and associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. A Malfunction, as defined in Paragraph 16 of this Consent Decree, does not constitute a Force Majeure Event unless the Malfunction also meets the definition of a Force Majeure Event, as provided in this Section. Conversely, a period of Malfunction may be excluded by the Settling Defendants from the calculations of emission rates and removal efficiencies, as allowed under this Paragraph, if the Malfunction constitutes a Force Majeure event.

## XV. DISPUTE RESOLUTION

139. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Parties.

140. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Parties advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with

regard to such dispute. The Parties receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

141. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually-agreed-upon alternative dispute resolution ("ADR") forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

142. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide the Settling Defendants with a written summary of their position regarding the dispute. The written position provided by the Plaintiffs shall be considered binding unless, within forty-five (45) calendar days thereafter, the Settling Defendants seeks judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) calendar days of filing.

143. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the Parties to the dispute.

144. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to

reach agreement.

145. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. The Settling Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule, provided that the Settling Defendants shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

146. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 142, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

147. This Paragraph shall govern all disputes under this Consent Decree between any Party regarding the BACT Determination provided by NDDH under Section V(B) of this Consent Decree. The Settling Defendants hereby waive their rights to challenge or dispute NDDH's BACT Determination other than through this Paragraph, which shall constitute the sole means by which the Settling Defendants may dispute such determination.

a. If any Party does not agree, in whole or in part, with NDDH's BACT Determination or with the 30-Day Rolling Average $NO_x$ Emission Rate established by NDDH as part of its BACT Determination, it shall notify the other Parties within thirty (30) days of receipt of the BACT Determination. The notice

shall describe the particular reason(s) for disagreeing with NDDH's BACT Determination. The disputing Party shall bear the burden of proof throughout the dispute resolution process. The Parties to the dispute shall endeavor to resolve the dispute informally for up to thirty (30) days following issuance of such notice.

b. If the Parties to the dispute do not reach an agreement during this informal dispute resolution process, each disputing Party shall provide the other Parties with a written summary of its position within thirty (30) calendar days after the end of the informal process. The written position(s) provided by the State shall be considered binding unless, within forty-five (45) calendar days thereafter, a Party files with this Court a petition which describes the nature of the dispute and seeks judicial resolution. The other Parties to the dispute shall respond to the petition(s) within forty-five (45) calendar days of each such filing.

c. The Court shall sustain the decision by NDDH unless the Party disputing the BACT Determination demonstrates that it is not supported by the state administrative record and not reasonable in light of applicable statutory and regulatory provisions.

## XVI. PERMITS

148. Unless expressly stated otherwise in this Consent Decree (e.g. Paragraph 109), in any instance where otherwise applicable law or this Consent Decree requires the Settling Defendants to secure a permit to authorize construction or operation of any device, including all preconstruction, construction, and operating permits required under state law, the Settling

Defendants shall make such application in a timely manner. The United States and NDDH will use their best efforts to expeditiously review all permit applications submitted by the Settling Defendants in order to meet the requirements of this Consent Decree.

149. When permits are required, the Settling Defendants shall complete and submit applications for such permits to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request, including requests for additional information by the permitting authorities. Any failure by the Settling Defendants to submit a timely permit application for any Unit at the Milton R. Young Station shall bar any use by the Settling Defendants of Section XIV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

150. Notwithstanding the reference to the Title V permit in this Consent Decree, the enforcement of the permit shall be in accordance with its own terms and the Act. The Title V permit shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXVI (Conditional Termination of Enforcement Under Consent Decree) of this Consent Decree.

151. Within ninety (90) days after entry of this Consent Decree, the Settling Defendants shall amend any applicable Title V permit application, or apply for amendments of their Title V permit, to include a schedule for all unit-specific and plant-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, emission rates, removal efficiencies, tonnage limitations, and the requirements pertaining to the surrender of $SO_2$ Allowances.

152. Within one (1) year from the commencement of operation of each pollution control device to be installed or upgraded on a Unit under this Consent Decree, the Settling Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree in either a federally enforceable permit (other than a Title V permit) or amendments to the North Dakota State Implementations Plan ("SIP"). The permit or SIP amendment shall require compliance with the following: (a) any applicable 30-Day Rolling Average Emission Rate or 30-Day Rolling Average Removal Efficiency, (b) the allowance surrender requirements set forth in this Consent Decree, and (c) any applicable Tonnage limitations set forth in this Consent Decree.

153. The Settling Defendants shall provide the United States with a copy of each application for a federally enforceable permit or SIP amendment, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity. The Settling Defendants and the NDDH agree to incorporate the $SO_2$ limitations in Subparagraphs 50(c) (and Subparagraph 50(d), if applicable) as federally-enforceable limits for the Settling Defendants in future permitting proceedings.

154. If the Settling Defendants sell or transfer to an entity unrelated to the Settling Defendants ("Third Party Purchaser") part or all of an ownership interest in a Unit ("Ownership Interest") covered under this Consent Decree, the Settling Defendants shall comply with the requirements of Paragraphs 148 through 153 with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, the Settling Defendants remains the holder of the permit for such facility.

## XVII. INFORMATION COLLECTION AND RETENTION

155. Any authorized representative of the Plaintiffs, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility covered under this Consent Decree at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the Plaintiffs in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by the Settling Defendants or their representatives, contractors, or consultants; and

d. assessing the Settling Defendants' compliance with this Consent Decree.

156. The Settling Defendants shall retain, and instruct their contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in their or their contractors' or agents' possession or control, and that directly relate to the Settling Defendants' performance of their obligations under this Consent Decree, until December 31, 2020. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

157. All information and documents submitted by the Settling Defendants pursuant to this Consent Decree shall be subject to public disclosure based on requests under applicable law providing for such disclosure unless (a) the information and documents are subject to legal privileges or protection or (b) the Settling Defendants claim and substantiate in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

158. Nothing in this Consent Decree shall limit the authority of the Plaintiffs to conduct tests and inspections at facilities covered under this Consent Decree under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

## XVIII. NOTICES

159. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DOJ# 90-5-2-1-07717

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

U. S. EPA, Region 8
Director, Office of Enforcement, Compliance, and Environmental Justice
999 18th Street, Suite 300
Denver, Colorado 80202-2466

As to the State of North Dakota:

Director, Air Quality Division
North Dakota Department of Health

Bismark, North Dakota 58506-5520

As to the Settling Defendants:

David Sogard, General Counsel
John Graves, Environmental Manager
1822 State Mill Road
P.O. Box 13200
Grand Forks, ND 58208-3200

160. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or delivery service; (b) certified or registered mail, return receipt requested; or (c) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions (a) sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service. All notifications, communications, and submissions made by electronic means shall be electronically signed and certified, and shall be deemed submitted on the date that the Settling Defendants receive written acknowledgment of receipt of such transmission.

161. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Parties with a notice setting forth such new notice recipient or address.

## XIX. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

162. If the Settling Defendants propose to sell or transfer part or all of their ownership interest in any of their real property or operations subject to this Consent Decree ("Ownership Interest") to an entity unrelated to the Settling Defendants ("Third Party Purchaser"), they shall

advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XVIII (Notices) at least sixty (60) days before such proposed sale or transfer.

163. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and the Plaintiffs have executed, and the Court has approved, a modification pursuant to Section XXII (Modification) of this Consent Decree making the Third Party Purchaser a party defendant to this Consent Decree and jointly and severally liable with the Settling Defendants for all the requirements of this Consent Decree that may be applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 165, below.

164. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between the Settling Defendants and any Third Party Purchaser as long the requirements of this Consent Decree are met. In addition, this Consent Decree shall not be construed to prohibit a contractual allocation–as between the Settling Defendants and any Third Party Purchaser of Ownership Interests–of the burdens of compliance with this Decree, provided that both the Settling Defendants and such Third Party Purchaser shall remain jointly and severally liable to the Plaintiffs for the obligations of the Decree applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 165.

165. If the Plaintiffs agree, the United States, the State, the Settling Defendants and the Third Party Purchaser that has become a party defendant to this Consent Decree pursuant to Paragraph 163 may execute a modification that relieves Minnkota and/or Square Butte of their liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests.

Notwithstanding the foregoing, however, the Settling Defendants may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections VIII (Additional Injunctive Relief) and IX (Civil Penalty). The Settling Defendants may propose and the Plaintiffs may agree to restrict the scope of joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the purchased or transferred Ownership Interests to the extent such obligations may be adequately separated in an enforceable manner.

## XX. EFFECTIVE DATE

166. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

## XXI. RETENTION OF JURISDICTION

167. **Continuing Jurisdiction.** The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

## XXII. MODIFICATION

168. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by all Parties. Where the modification constitutes a material change to any term of this Consent Decree, it shall be effective only upon approval by the Court.

## XXIII. GENERAL PROVISIONS

169. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The removal efficiencies and emission rates set forth herein do not relieve the Settling Defendants from any obligation to comply with other state and federal requirements under the Clean Air Act, including the Settling Defendants' obligations to satisfy any state modeling requirements set forth in the North Dakota State Implementation Plan. Unless otherwise indicated herein, citations to statutes or regulations herein shall mean the version of the statutes or regulations in force as of July 1, 2005.

170. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

171. In any subsequent administrative or judicial action initiated by the Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, the Settling Defendants shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to, or shall, affect the validity of Section X (Resolution of Claims) of this Consent Decree.

172. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve the Settling Defendants of their obligations to comply with all applicable federal, state, and local laws and regulations. Nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties, injunctive relief or other relief under the Act or other federal, state, or local statutes, regulations, or permits.

173. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Consent Decree, every other term used in this Consent Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Consent Decree what such term means under the Act or those implementing regulations.

174. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

175. Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

176. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. The Settling Defendants shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending

upon whether the limit is expressed to three or two significant digits. For example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. The Settling Defendants shall report data to the number of significant digits in which the standard or limit is expressed.

177. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

178. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supersedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

179. The United States and the Settling Defendants shall bear their own costs and attorneys' fees.

## XXIV. SIGNATORIES AND SERVICE

180. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

181. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

182. Each Party hereby agrees to accept service of process by mail with respect to all

matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

## XXV. PUBLIC COMMENT

183. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. The Settling Defendants shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified the Settling Defendants, in writing, that the United States no longer supports entry of the Consent Decree.

## XXVI. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER CONSENT DECREE

184. **Termination as to Completed Tasks.** As soon as the Settling Defendants complete a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, the Settling Defendants may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

185. **Conditional Termination of Enforcement Through the Consent Decree.** After the Settling Defendants:

a. have successfully completed construction, and have maintained operation, of all

pollution controls as required by this Consent Decree;

b. have obtained a final Title V permit (I) as required by the terms of this Consent Decree; (ii) that cover all units in this Consent Decree; and (iii) that include as enforceable permit terms all of the Unit performance and other requirements specified in Section XVI (Permits) of this Consent Decree; and

c. certified that the date is later than December 31, 2015;

then the Settling Defendants may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of the Settling Defendants' certification, then, for any Consent Decree violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

186. **Resort to Enforcement under this Consent Decree.** Notwithstanding Paragraph 187, if enforcement of a provision in this Consent Decree cannot be pursued by a Party under the applicable Title V permit, or if a Consent Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Consent Decree at any time, unless and until the Settling Defendants have secured a source-specific revision to the North Dakota State Implementation Plan to reflect the emission limitations, emissions monitoring, and allowance surrender requirements set forth in this Consent Decree.

## XXVII. FINAL JUDGMENT

187. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment in the above-captioned matter between the Plaintiffs and the Settling Defendants.

SO ORDERED, THIS _____ DAY OF _____, 2006.

_____
UNITED STATES DISTRICT COURT JUDGE

**FOR THE UNITED STATES OF AMERICA:**

_____
SUE ELLEN WOOLDRIDGE
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

_____
MATTHEW W. MORRISON
Senior Counsel
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice

GRANTA Y. NAKAYAMA
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

ADAM M. KUSHNER
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

JEFFREY A. KODISH
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

_____

CAROL RUSHIN
Assistant Regional Administrator
Office of Enforcement, Compliance
and Environmental Justice

_____

BRENDA MORRIS
Enforcement Attorney
U.S. Environmental Protection Agency
Region 8

**FOR THE STATE OF NORTH DAKOTA:**

_____
TERRY L. DWELLE, MD, MPHTM
State Health Officer
North Dakota Dep't of Health

_____
WAYNE STENEHJEM
Attorney General
Attorney for North Dakota

**FOR DEFENDANT MINNKOTA POWER COOPERATIVE, INC.:**

_____

DAVID LOER
President & CEO

**FOR DEFENDANT SQUARE BUTTE ELECTRIC COOPERATIVE:**

_____

DAVID LOER
General Manager

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF WISCONSIN

| | | |
|---|---|---|
| UNITED STATES OF AMERICA | ) | |
| | ) | |
| and | ) | |
| | ) | |
| MICHAEL A. COX, Attorney General | ) | |
| of the State of Michigan, ex rel. | ) | |
| MICHIGAN DEPARTMENT | ) | |
| OF ENVIRONMENTAL QUALITY | ) | Civil Action No. 03-C-0371 |
| | ) | |
| Plaintiffs, | ) | |
| | ) | |
| v. | ) | |
| | ) | |
| WISCONSIN ELECTRIC POWER COMPANY, | ) | |
| | ) | |
| Defendant. | ) | |
| | ) | |
| _____ | ) | |

AMENDED CONSENT DECREE

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WHEREAS, on April 29, 2003, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA"), filed a Complaint against Wisconsin Electric pursuant to Sections 113(b) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b) and 7477, for injunctive relief and the assessment of civil penalties for alleged violations of:

(a) the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92;

(b) the nonattainment New Source Review provisions in Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515;

(c) the federally-enforceable State Implementation Plan developed by the State of Michigan (the "Michigan SIP"); and

(d) the federally-enforceable State Implementation Plan developed by the State of Wisconsin (the "Wisconsin SIP");

WHEREAS, in its Complaint, the United States alleges, *inter alia*, that Wisconsin Electric failed to obtain the necessary permits and install the controls necessary under the Act to reduce its sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that such emissions can damage human health and the environment;

WHEREAS, the United States alleges that its Complaint states claims upon which relief can be granted against Wisconsin Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Michael A. Cox, Attorney General of the State of Michigan, on behalf of the Michigan Department of Environmental Quality (the "State of Michigan"), has filed a Complaint

against Wisconsin Electric pursuant to Section 167 of the Act, 42 U.S.C. § 7477, and Section 5530 of Part 55 of Michigan's Natural Resources and Environmental Protection Act ("Part 55 of NREPA"), MCL § 324.5530, for injunctive relief and the assessment of civil fines for alleged violations of:

(a) the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92; and

(b) Section 5505 of Part 55 of NREPA, MCL § 324.5505;

WHEREAS, in its Complaint, the State of Michigan alleges, *inter alia*, that Wisconsin Electric failed to obtain the necessary permits and install the controls necessary under the Act and Section 5505 of Part 55 of NREPA to reduce its emissions of sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that such emissions can damage human health and the environment;

WHEREAS, the State of Michigan alleges that its Complaint states claims upon which relief can be granted against Wisconsin Electric under Section 167 of the Act, 42 U.S.C. § 7477, and Section 5505 of Part 55 of NREPA;

WHEREAS, Wisconsin Electric has not answered or otherwise responded to either the Complaint by the United States or the Complaint filed by the State of Michigan in light of the settlement memorialized in this Amended Consent Decree;

WHEREAS, Wisconsin Electric has denied and continues to deny the violations alleged in the Complaints, maintains that it has been and remains in compliance with the Act, Part 55 of NREPA, and is not liable for civil penalties, fines, or injunctive relief, and states that it is

agreeing to the obligations imposed by this Amended Consent Decree solely to avoid the costs and uncertainties of litigation and to reduce its emissions;

WHEREAS, Wisconsin Electric, consistent with its environmental, health and safety policy, met with the United States in February 2003, to resolve those Parties' respective goals for achieving emission reductions of certain emissions at the electric generating stations covered under this Amended Consent Decree;

WHEREAS, EPA provided Wisconsin Electric and the States of Michigan and Wisconsin with actual notice of violations pertaining to Wisconsin Electric's alleged violations, in accordance with Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1);

WHEREAS, Wisconsin Electric and the United States thereafter met with the State of Michigan in April 2003 to discuss resolution of the Parties' respective goals for achieving emission reductions of certain emissions at the Presque Isle Generating Station in Michigan;

WHEREAS, the Parties anticipate that the installation and operation of pollution control equipment pursuant to this Amended Consent Decree will achieve significant reductions in $SO_2$, $NO_x$ and PM emissions and thereby improve air quality and that certain actions that Wisconsin Electric has agreed to undertake are expected to advance technologies and methodologies for reducing certain air emissions, including mercury;

WHEREAS, nothing in this Amended Consent Decree is intended to prohibit the use by the State of Michigan of emission reductions under this Amended Consent Decree to demonstrate attainment with §110 of the Act (42 U.S.C. § 7410);

WHEREAS, Wisconsin Electric has begun the process of retiring the coal-fired units at the Port Washington Generating Station and has applied for and received permits to construct two new combined cycle natural gas units at that facility;

WHEREAS, Wisconsin Electric is seeking approval, including air emissions permits, to construct three new coal-fired units in Wisconsin at a site adjacent to the South Oak Creek Generating Station, designated as the Elm Road Generating Station;

WHEREAS, EPA supports the construction of cleaner power plants to meet growing energy demands;

WHEREAS, the Plaintiffs and Wisconsin Electric have agreed, and the Court by entering this Amended Consent Decree finds: that this Consent Decree has been negotiated in good faith and at arms length; that this settlement is fair, reasonable, in the best interest of the Parties and in the public interest; that the settlement is consistent with the goals of the Act; and that entry of this Amended Consent Decree without further litigation is the most appropriate means of resolving this matter;

and

WHEREAS, the Plaintiffs and Wisconsin Electric have consented to entry of this Amended Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaints it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

## I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113(b) and 167 of the Act, 42 U.S.C. §§ 7413(b) and 7477, MCL §324.5530, the Michigan SIP, 40 C.F.R. § 52.1180(b); 45 Fed. Reg. 8348 (February 7, 1980), and the Wisconsin SIP, 40 C.F.R. § 52.2570; Wis. Admin. Code, NR § 405. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the Plaintiffs' underlying Complaints, Wisconsin Electric waives all objections and defenses that it may have to the claims set forth in the underlying Complaints, and to the jurisdiction of the Court over Wisconsin Electric and this action, and to venue in this District. Wisconsin Electric shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. For purposes of the Complaints filed by the Plaintiffs in this matter and resolved by the Consent Decree, and for purposes of entry and enforcement of this Decree, Wisconsin Electric waives any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the Plaintiffs and Wisconsin Electric. Except as provided by Section XXVII (Public Comment), the Parties consent to entry of this Consent Decree without further notice.

## II. APPLICABILITY

2. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the United States, the State of Michigan, and Wisconsin Electric, its successors and assigns, and Wisconsin Electric's officers, employees, and agents solely in their capacities as such.

3. Wisconsin Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, Wisconsin Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Wisconsin Electric shall not assert as a defense the failure of its officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Wisconsin Electric establishes that such failure resulted from a Force Majeure Event, as defined in Paragraph 150 of this Consent Decree.

## III. DEFINITIONS

4. A "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lb/mmBTU for the current day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all startup, shut down and Malfunction periods within each Operating Day. A Malfunction shall be excluded from this Emission Rate, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

5. "30-Day Rolling Average Removal Efficiency" means the percent reduction in the mass of a pollutant achieved by a Unit's pollution control device over a 30-day period. This percentage shall be calculated by subtracting the Unit's outlet 30-Day Rolling Average Emission Rate from the Unit's inlet 30-Day Rolling Average Emission Rate, dividing that difference by

the Unit's inlet 30-Day Rolling Average Emission Rate, and then multiplying by 100. A new 30-Day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all periods of startup, shutdown and Malfunction within an Operating Day. A Malfunction shall be excluded from this removal efficiency, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

6. "Air Quality Control Region" means a geographic area designated under Section 107(c) of the Act, 42 U.S.C. § 7407(c).

7. "Baseline" means the annual average emissions of $SO_2$ and $NO_x$ of the Plants in the Wisconsin Electric System for calendar years 2000 and 2001, as measured under 40 C.F.R. Part 75.

8. "Boiler Island" means a Unit's (A) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (B) combustion air system; (C) steam generating system (i.e., firebox, boiler tubes and walls); and (D) draft system (excluding the stack), as further described in "Interpretation of Reconstruction," by John B. Rasnick, U.S. EPA (November 25, 1986) and the attachments thereto.

9. "BH" means baghouse, a pollution control device for the reduction of particulate matter ("PM").

10. "Capital Expenditure" means all capital expenditures, as defined by Generally Accepted Accounting Principles ("GAAP"), excluding the cost of installing or upgrading pollution control devices.

11. “CEMS” or “Continuous Emission Monitoring System” means, for obligations involving $NO_x$ and $SO_2$ under this Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

12. “Clean Air Act” or “Act” means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

13. “Consent Decree” or “Decree” means this Amended Consent Decree.

14. “Elm Road Generating Station” means the proposed coal-fired electric generating units, for which Wisconsin Electric is seeking regulatory approval to construct at a site adjacent to the South Oak Creek Generating Station.

15. “Emission Rate” means the number of pounds of pollutant emitted per million BTU of heat input (“lb/mmBTU”), measured in accordance with this Consent Decree.

16. “EPA” means the United States Environmental Protection Agency.

17. “ESP” means electrostatic precipitator, a pollution control device for the reduction of particulate matter (“PM”).

18. “Existing Units” means those Units included in the Wisconsin Electric System.

19. “Flue gas desulfurization system,” or “FGD,” means a pollution control device that employs flue gas desulfurization technology for the reduction of sulfur dioxide.

20. “Fossil fuel” means any hydrocarbon fuel, including coal, petroleum oil, or natural gas.

21. “Improved Unit” means, in the case of $NO_x$, a Wisconsin Electric System Unit scheduled under this Decree to be equipped with SCR (or equivalent NOx control technology approved pursuant to Paragraph 59) or to be retired, and, in the case of $SO_2$, a Wisconsin Electric

System Unit scheduled under this Decree to be equipped with an FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 74) or to be retired. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for the other.

22. "lb/mmBTU" mean one pound of a pollutant per million British Thermal Units of heat input.

23. "Malfunction" means malfunction as that term is defined under 40 C.F.R.§ 60.2.

24. "MW" means a megawatt, or one million Watts.

25. "MDEQ" means the Michigan Department of Environmental Quality

26. "National Ambient Air Quality Standards" means national air quality standards promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

27. "New Units" means any coal-fired or natural gas fired units that commence operation after entry of this Consent Decree, including but not limited to the re-powered natural gas units at the Port Washington Generating Station.

28. "$NO_x$" means oxides of nitrogen, as measured in accordance with the provisions of this Consent Decree.

29. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7510-7515, 40 C.F.R. Part 51.

30. "NSPS" means New Source Performance Standards within the meaning of Part A of Subchapter I, of the Clean Air Act, 42 U.S.C. § 7411, 40 C.F.R. Part 60.

31. "Operating Day" means any calendar day on which a Unit fires fossil fuel.

32. “Other Unit” means any Unit of the Wisconsin Electric System that is not an Improved Unit for the pollutant in question. A Unit may be an Improved Unit for NOx and an Other Unit for $SO_2$ and vice versa.

33. “PM Control Device” means an electrostatic precipitator (“ESP”) or a baghouse (“BH”), devices which reduce emissions of particulate matter (“PM”).

34. “Part 55 of NREPA” means Part 55, Air Pollution Control, of Michigan’s Natural Resources and Environmental Protection Act, MCL §§ 324.5501-42.

35. “Parties” means Wisconsin Electric, the State of Michigan and the United States.

36. “Permitting State” means the state in which a particular Unit is located from which Wisconsin Electric is required to obtain permits, licenses, or approvals in order to install or operate a source of air pollution.

37. “Plaintiffs” means the United States and the State of Michigan.

38. “Plant-specific 12-Month Rolling Tonnage” means the sum of the tons of pollutant in question emitted from the applicable plant in the most recent month and the previous eleven (11) months. A new Plant-Specific 12-Month Rolling Tonnage will be calculated for each new complete month.

39. “PM” means particulate matter, as measured in accordance with the provisions of this Consent Decree.

40. “PM CEMS” or “PM continuous emission monitoring system” means equipment that samples, analyzes, measures, and provides PM emissions data -- by readings taken at frequent intervals – and makes an electronic or paper record of the PM emissions measured.

41. “PM Emission Rate” shall mean the average number of pounds of PM emitted per million BTU of heat input (“lb/mmBTU”), as measured in annual stack tests, in accordance with the reference methods set forth in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17.

42. “Project Dollars” means Wisconsin Electric’s expenditures and payments incurred or made in carrying out the projects identified in Section IX of this Consent Decree (Environmental Projects) to the extent that such expenditures or payments both: (a) comply with the Project Dollar and other requirements set by this Consent Decree in Section IX of this Consent Decree (Environmental Projects); and (b) constitute Wisconsin Electric’s external costs for contractors, vendors, and equipment, and its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with “GAAP”.

43. “PSD” means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

44. “SCR” means a device that employs selective catalytic reduction technology for the reduction of nitrogen oxides.

45. “$SO_2$” means sulfur dioxide, as measured in accordance with this Consent Decree.

46. “$SO_2$ Allowance” means an “allowance,” as defined at 42 U.S.C. § 7651a(3): an authorization, allocated to an affected unit, by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide.

47. “State of Michigan” means Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality.

48. “System-wide 12-Month Rolling Average Emission Rate” means (a) summing the pounds of pollutant in question emitted from the Wisconsin Electric System during the most recent complete month and the previous eleven (11) months, (b) summing the heat input to the Wisconsin Electric System in mmBTU during the most recent complete month and the previous eleven (11) months, and (c) dividing the total number of pounds of pollutants emitted during the twelve (12) months by the total heat input during the twelve (12) months, and expressing the resulting figure in lbs/mmBTU. A new System-wide 12-Month Rolling Average Emission Rate shall be calculated for each new complete month. Each “System-wide 12-Month Rolling Average Emission Rate” shall include all start-up, shut down and Malfunction periods within each complete month.

49. “System-wide 12-Month Rolling Tonnage” means the sum of the tons of pollutant in question emitted from the Wisconsin Electric System in the most recent month and the previous eleven (11) months. A new System-wide 12-Month Rolling Tonnage will be calculated for each new complete month.

50. “Title V Permit” means the permit required of Wisconsin Electric’s major sources under Subchapter V of the Clean Air Act, 42 U.S.C. §§ 7661-7661e.

51. “Unit” means, for the purpose of this Consent Decree, collectively, the coal pulverizer, the stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment, or systems necessary for the production of electricity. An electric utility steam generating station may be comprised of one or more Units.

52. "Unit-Specific 12-Month Rolling Tonnage" means the sum of the tons of pollutant in question emitted from the applicable Unit in the most recent month and the previous eleven (11) months. A new Unit-Specific 12-Month Rolling Tonnage will be calculated for each new complete month.

53. "WEC" means Wisconsin Energy Corporation, the parent company of Wisconsin Electric and W.E. Power.

54. "W.E. Power" means W.E. Power LLC, a subsidiary of WEC and an affiliate of Wisconsin Electric.

55. "Wisconsin Electric" means the Wisconsin Electric Power Company.

56. "Wisconsin Electric System" means, solely for purposes of this Consent Decree, the following twenty-three (23) coal-fired, electric utility steam generating Units (with the rated $MW_{(net)}$ capacity of each Unit noted in parentheses):

- Presque Isle Generating Station in Marquette, Michigan - Unit 1 (25 MW), 2 (37.5 MW), 3 (54.4 MW), 4 (57.8 MW), 5 (90 MW), 6 (90 MW), 7 (90 MW), 8 (90 MW), and 9 (90 MW);
- Pleasant Prairie Generating Station in Kenosha, Wisconsin - Units 1 (616.6 MW) and 2 (616.6 MW);
- South Oak Creek Generating Station in Oak Creek, Wisconsin - Units 5 (275 MW), 6 (275 MW), 7 (317.6 MW), and 8 (324 MW);
- Port Washington Generating Station in Port Washington, Wisconsin - Units 1 (80 MW), 2 (80 MW), 3 (80 MW), and 4 (80 MW);

- Valley Generating Station in Milwaukee, Wisconsin - Units 1 (80 MW), 2 (80 MW), 3 (80 MW), and 4 (80 MW).

## IV. UNITS TO BE CONTROLLED OR RETIRED

57. Wisconsin Electric shall either satisfy the emission control requirements of Paragraphs 58 and 73 with regard to the following Units or retire and permanently cease to operate the following Units within the Wisconsin Electric System by the following dates:

| **Unit** | **Date by which Wisconsin Electric Must Control or Cease to Operate Unit** |
|---|---|
| Port Washington Unit 4 | Upon Entry of this Consent Decree |
| Port Washington Unit 1 | December 31, 2004 |
| Port Washington Unit 2 | December 31, 2004 |
| Port Washington Unit 3 | December 31, 2004 |
| Oak Creek Unit 5 | December 31, 2012 |
| Oak Creek Unit 6 | December 31, 2012 |
| Presque Isle Unit 1 | December 31, 2012 |
| Presque Isle Unit 2 | December 31, 2012 |
| Presque Isle Unit 3 | December 31, 2012 |
| Presque Isle Unit 4 | December 31, 2012 |

## V. $NO_x$ EMISSION REDUCTIONS AND CONTROLS

### A. $NO_x$ Emission Controls

58. Wisconsin Electric shall install and commence continuous operation of Selective Catalytic Reduction technology ("SCR") (or equivalent $NO_x$ control technology approved pursuant to Paragraph 59) so as to achieve a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU $NO_x$ on the following Units within the Wisconsin Electric System by the dates set forth in the following table.

| **Unit** | **Date by Which Wisconsin Electric Must Complete Installation and Continuously Operate SCR** | **Date by Which Wisconsin Electric Must Comply with the 30-Day Rolling Average Emission Rate** |
|---|---|---|
| Pleasant Prairie Unit 2 | December 31, 2003 | January 30, 2004 |
| Pleasant Prairie Unit 1 | December 31, 2006 | January 30, 2007 |
| Oak Creek Unit 7 | December 31, 2012 | January 30, 2013 |
| Oak Creek Unit 8 | December 31, 2012 | January 30, 2013 |

59. With prior written notice to and approval from EPA, Wisconsin Electric may, in lieu of installing and operating any such SCR, install and operate equivalent $NO_x$ control technology so long as such equivalent $NO_x$ control technology achieves a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU $NO_x$.

60. Wisconsin Electric shall continuously operate SCR (or equivalent NOx control technology approved pursuant to Paragraph 59) at all times that the Unit it serves is in operation consistent with the technological limitations, manufacturers' specifications, and good operating practices, for the SCR or equivalent technology.

61. Wisconsin Electric shall also operate either low $NO_x$ burners ("LNB") or combustion control technology on the following Units within the Wisconsin Electric System. Such low-$NO_x$ burner or combustion control technology shall be operational in accordance with the following schedule:

| **Units to be Controlled** | **$NO_x$ Control** | **Deadline for Commencement of Operation** |
|---|---|---|
| Valley Boiler 1 | LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software) | 30 days after the date of lodging of this Consent Decree |
| Valley Boiler 2 | LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software) | 30 days after the date of lodging of this Consent Decree |
| Valley Boiler 3 | LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software) | 30 days after the date of lodging of this Consent Decree |
| Valley Boiler 4 | LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software) | 30 days after the date of lodging of this Consent Decree |
| Presque Isle Unit 5 | LNB and Combustion Optimization Software | December 31, 2003 |
| Presque Isle Unit 6 | LNB and Combustion Optimization Software | December 31, 2003 |
| Presque Isle Unit 7 | LNB and Combustion Optimization Software (Existing LNB) | December 31, 2005 |
| Presque Isle Unit 8 | LNB and Combustion Optimization Software (Existing LNB) | December 31, 2005 |
| Presque Isle Unit 9 | LNB and Combustion Optimization Software (Existing LNB) | December 31, 2006 |

B. System-Wide $NO_x$ Emission Limits

62. Wisconsin Electric shall not exceed the Wisconsin Electric System-wide 12-Month Rolling Average Emission Rates for $NO_x$ as specified below.

| **For the 12-Month Period Commencing on the Date Specified Below, and Each 12-Month Period Thereafter:** | **System-wide 12-Month Rolling Average Emission Rate for $NO_x$** |
|---|---|
| January 1, 2005 | 0.270 lbs/mmBTU |
| January 1, 2007 | 0.190 lbs/mmBTU |
| January 1, 2013 | 0.170 lbs/mmBTU |

63. In addition to meeting the system-wide emission limit set forth in the preceding Paragraph, Wisconsin Electric shall not emit $NO_x$ on a System-wide 12-Month Rolling Tonnage basis from the Wisconsin Electric System in an amount greater than the following number of tons.

| **For the 12-Month Period Commencing on the Date Specified Below, and Each 12-Month Period Thereafter:** | **System-wide 12-Month Rolling Tonnage Limitation for $NO_x$** |
|---|---|
| January 1, 2005 | 31,500 tons |
| January 1, 2007 | 23,400 tons |
| January 1, 2013 | 17,400 tons |

Wisconsin Electric shall meet the above $NO_x$ tonnage limitations exclusively through the operation of all control equipment required to be installed and operated by this Decree, Unit retirements, and any additional control equipment that Wisconsin Electric installs and operates. Wisconsin Electric shall not use $NO_x$ allowances or credits to comply with these limitations.

C. NOx Emission Limitations at Presque Isle Units 1 and 2

64. In addition to meeting the System-wide 12-Month Rolling Tonnage limitations for $NO_x$ set forth in Paragraph 63, after December 31, 2003, Wisconsin Electric shall not emit $NO_x$ from the Units 1 and 2 at the Presque Isle Generating Plant in an amount greater than 130 and 194 tons per year, respectively, based upon a Unit-Specific 12-Month Rolling Tonnage. If a Unit exceeds the applicable Unit-Specific 12-Month Rolling Tonnage limitation specified in this Paragraph, Wisconsin Electric shall install and operate LNB technologies on that Unit no later than December 31 of the calendar year following such exceedance.

65. So long as Units 1 through 4 at the Presque Isle Generating Station discharge through a common stack, are of the same design and combust the same fuel, Wisconsin Electric shall determine monthly mass emissions of $NO_x$ by apportioning $NO_x$ emissions from the common stack to Units 1 and 2. To apportion emissions, Wisconsin Electric shall utilize the load based apportionment protocol used in the Acid Rain Program to apportion heat rates to units that share a common stack. Each month, Wisconsin Electric shall calculate the Unit-Specific 12-month Rolling Tonnage of $NO_x$ mass (tons/year) attributed to Units 1 and 2.

D. Use of $NO_x$ Emission Allowances

66. For any and all actions taken by Wisconsin Electric to conform to the requirements of this Consent Decree, Wisconsin Electric shall not use, sell, or trade any resulting

$NO_x$ emission allowances or credits in any emission trading or marketing program of any kind, except as provided in this Consent Decree.

67. $NO_x$ emission allowances or credits allocated to the Wisconsin Electric System by the Administrator of EPA under the Act, or by any State under its State Implementation Plan, may be used by Wisconsin Electric to meet its own federal and/or state Clean Air Act regulatory requirements for any Existing Unit or New Unit owned or operated, in whole or in part, by Wisconsin Electric.

68. Nothing in this Consent Decree shall preclude Wisconsin Electric from using, selling, or transferring $NO_x$ emission reductions below the emission requirements of Wi. Admin. Code NR 428 among the units in the Wisconsin Electric System in order to demonstrate compliance with either Wi. Admin. Code NR 428 or Mich. Admin. Code Rule 801. Use of emission reductions generated from the Wisconsin Electric System to comply with the requirements of Mich. Admin. Code Rule 801 will conform to the Memorandum of Understanding ("MOU") among the State of Wisconsin, the State of Michigan and Wisconsin Electric, dated November 8, 2002, as that MOU may be amended from time to time.

69. Nothing in this Consent Decree shall preclude Wisconsin Electric from using, selling or transferring excess $NO_x$ emission allowances or credits that may arise as a result of:

a. activities which occur prior to the date of entry of this Consent Decree;

b. achieving $NO_x$ emission reductions at an Improved Unit that are below both the 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU $NO_x$ and the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or

c. the $NO_x$ emission reductions achieved by virtue of Wisconsin Electric's installation and operation any $NO_x$ pollution controls prior to the dates required under Section V ($NO_x$ Emission Reductions and Controls) of this Consent Decree,

so long as Wisconsin Electric timely reports the creation of such allowances or credits in accordance with Section XII of this Consent Decree. For purposes of this Paragraph, excess $NO_x$ emission allowances or credits equal the number of tons of $NO_x$ that Wisconsin Electric removed from its emissions that are in excess of the $NO_x$ reductions required by this Decree.

70. Wisconsin Electric may not purchase or otherwise obtain $NO_x$ allowances or credits from another source for purposes of complying with the requirements of this Consent Decree. However, nothing in this Consent Decree shall prevent Wisconsin Electric from purchasing or otherwise obtaining $NO_x$ allowances or credits from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

E. General $NO_x$ Provisions

71. In determining Emission Rates for $NO_x$, Wisconsin Electric shall use CEMS in accordance with those reference methods specified in 40 C.F.R. Part 75.

72. In calculating the 30-day Rolling Average Emission Rate or System-wide 12-Month Rolling Average Emission Rate for $NO_x$ for a given Unit or group of Units, Wisconsin Electric shall not exclude any period of time that the Unit(s) is/are in operation, including periods in which any $NO_x$ emission control technology for the Unit(s) is not in operation.

## VI. $SO_2$ EMISSION REDUCTIONS AND CONTROLS

### A. $SO_2$ Emission Controls

#### 1. New FGD Installations

73. Wisconsin Electric shall install and commence continuous operation of Flue Gas Desulfurization technology ("FGD") (or equivalent $SO_2$ control technology approved pursuant to Paragraph 74) so as to achieve either a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU $SO_2$ or a 30-day Rolling Average $SO_2$ Removal Efficiency of at least 95 percent on the following Units within the Wisconsin Electric System by the dates specified below.

| **Unit** | **Date by which Wisconsin Electric Must Complete Installation and Continuously Operate FGD** | **Date by which Wisconsin Electric Must Comply with 30-Day Rolling Average Emission Rate** |
|---|---|---|
| Pleasant Prairie Unit 1 | December 31, 2006 | January 30, 2007 |
| Pleasant Prairie Unit 2 | December 31, 2007 | January 30, 2008 |
| Oak Creek Unit 7 | December 31, 2012 | January 30, 2013 |
| Oak Creek Unit 8 | December 31, 2012 | January 30, 2013 |

74. In lieu of installing and operating such FGDs, Wisconsin Electric may, with prior written notice to and approval from EPA, install and operate equivalent $SO_2$ control technology, so long as such equivalent $SO_2$ control technology achieves a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU $SO_2$ or a 30-day Rolling Average Removal Efficiency of at least 95 percent.

75. Wisconsin Electric shall continuously operate each FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 74) in the Wisconsin Electric System at all

times that the Unit it serves is in operation, except that, following startup of the Unit, Wisconsin Electric need not operate such control technology until the Unit is fired with any coal. Wisconsin Electric shall use good operating practices at all times that the Unit is in operation.

B. System-Wide $SO_2$ Emission Limits

76. Wisconsin Electric shall not exceed the Wisconsin Electric System-Wide 12-Month Rolling Average Emission Rates for $SO_2$ as specified below.

| **For the 12-Month Period Commencing on the Date Specified Below, and Each 12-Month Period Thereafter:** | **System-wide 12-Month Rolling Average Emission Rate for $SO_2$** |
|---|---|
| January 1, 2005 | 0.76 lbs/mmBTU |
| January 1, 2007 | 0.61 lbs/mmBTU |
| January 1, 2008 | 0.45 lbs/mmBTU |
| January 1, 2013 | 0.32 lbs/mmBTU |

77. In addition to installing the controls, retiring Units, achieving the $SO_2$ Emission Rates or Removal Efficiencies described in Paragraph 73, and surrendering the $SO_2$ Allowances required in this Consent Decree, Wisconsin Electric shall not emit $SO_2$ on a System-wide 12-Month Rolling Tonnage basis from the Wisconsin Electric System in an amount greater than the following number of tons.

| For the 12-Month Period Commencing on the Date Specified Below, and Each 12-Month Period Thereafter: | System-wide 12-Month Rolling Tonnage Limit for $SO_2$ |
|---|---|
| January 1, 2005 | 86,900 tons |
| January 1, 2007 | 74,400 tons |
| January 1, 2008 | 55,400 tons |
| January 1, 2013 | 33,300 tons |

Wisconsin Electric shall meet the above $SO_2$ tonnage limitations exclusively through the operation of all control equipment required to be installed and operated by this Decree, Unit retirements, and any additional control equipment that Wisconsin Electric installs and operates. Wisconsin Electric shall not use $SO_2$ allowances or credits to comply with these limitations.

C. Surrender of $SO_2$ Allowances

78. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for all units in the Wisconsin Electric System, so that such allowances can never be used to meet any compliance requirement under the Clean Air Act, the Michigan or Wisconsin State Implementation Plans, or this Consent Decree.

79. Beginning on January 1, 2004, Wisconsin Electric may use any $SO_2$ Allowances allocated by EPA to the Wisconsin Electric System only to satisfy the operational needs of Existing Units or New Units. Wisconsin Electric shall not sell or transfer any allocated $SO_2$ Allowances to a third party, except as provided in Paragraphs 80, 81 and 84 below. However, for the calendar years 2004 through 2007, Wisconsin Electric may bank $SO_2$ allowances

allocated by EPA to the Units in the Wisconsin Electric System for use at the Existing Units or New Units during the years 2004 through 2007.

80. For each calendar year, beginning with calendar year 2007, Wisconsin Electric shall surrender to EPA, or transfer to a non-profit third party selected by Wisconsin Electric for surrender, any $SO_2$ Allowances that exceed the operational needs of the Existing Units and New Units for $SO_2$ Allowances, collectively. Surrender shall occur annually thereafter and within 45 days of Wisconsin Electric's receipt from EPA of the Annual Deduction Reports for $SO_2$. In addition, in calendar year 2008, Wisconsin Electric shall surrender any allowances allocated by EPA to the Units in the Wisconsin Electric System that were banked and not used during the years 2004 through 2007. Wisconsin Electric shall surrender $SO_2$ Allowances by the use of applicable United States Environmental Protection Agency Acid Rain Program Allowance Transfer Form.

81. If any allowances are transferred directly to a third party, Wisconsin Electric shall include a description of such transfer in the next report submitted to the Plaintiffs pursuant to Section XII (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the $SO_2$ Allowances and a listing of the serial numbers of the transferred $SO_2$ Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient will not sell, trade, or otherwise exchange any of the allowances and will not use any of the $SO_2$ Allowances to meet any obligation imposed by any environmental law. No later than the next Section XII periodic report due 12 months after the first report due after the transfer, Wisconsin Electric shall include in a statement that the third-party recipient(s) surrendered the $SO_2$ Allowances for permanent surrender to EPA within one

year after Wisconsin Electric transferred the $SO_2$ Allowances to them. Wisconsin Electric shall not have complied with the $SO_2$ Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred $SO_2$ Allowances to EPA.

82. For all $SO_2$ Allowances surrendered to EPA, Wisconsin Electric shall first submit an $SO_2$ Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of the $SO_2$ Allowances held or controlled by Wisconsin Electric to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct. As part of submitting these transfer requests, Wisconsin Electric shall irrevocably authorize the transfer of these $SO_2$ Allowances and identify -- by name of account and any applicable serial or other identification numbers or station names -- the source and location of the $SO_2$ Allowances being surrendered.

83. The requirements in Paragraphs 79 and 80 of this Decree pertaining to Wisconsin Electric's use and retirement of $SO_2$ Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Decree in whole or in part.

84. Notwithstanding the provisions in Paragraph 79 and 80, nothing in this Consent Decree shall preclude Wisconsin Electric from using, banking, selling or transferring excess emission $SO_2$ allowances that may arise as a result of:

a. activities which occur prior to the date of entry of this Consent Decree;

b. achieving $SO_2$ emissions at an Improved Unit that are below both the 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU $SO_2$ and the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree;

c. achieving a 30-Day Rolling Average Removal Efficiency at an Improved Unit greater than 95 percent and achieving emissions below the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or

d. the installation and operation of any $SO_2$ pollution controls prior to the dates required under Section VI ($SO_2$ Emission Reductions and Controls) of this Consent Decree

so long as Wisconsin Electric timely reports such use under Section XII. For purposes of this Paragraph, excess $SO_2$ emission allowances equal the number of tons of $SO_2$ that Wisconsin Electric removed from its emissions that are in excess of the $SO_2$ reductions required by this Decree.

D. Fuel Limitations

85. Wisconsin Electric shall not burn coal having a sulfur content greater than any amount authorized by regulation or state permit at any Wisconsin Electric System Unit. Upon entry of the Consent Decree, Wisconsin Electric shall not receive petroleum coke at any Unit that is not controlled by an FGD (or equivalent $SO_2$ control technology approved pursuant to Paragraph 74), except that Wisconsin Electric may continue to receive petroleum coke at Presque Isle Units 1 through 6 until June 30, 2006.

E. General $SO_2$ Provisions

86. In determining Emission Rates for $SO_2$, Wisconsin Electric shall use CEMs in accordance with those reference methods specified in 40 C.F.R. Part 75 and 40 C.F.R. Part 60.

87. For Units that are required to be equipped with $SO_2$ control equipment and that are subject to the 95% removal provisions, the outlet $SO_2$ Emission Rate and the inlet $SO_2$

Emission Rate shall be determined in accordance with 40 C.F.R. § 75.15 (using $SO_2$ CEMS data from both the inlet and outlet of the control device). For Units that are required to meet a 0.100 lb/mmBTU limitation, the $SO_2$ Emission Rate shall be determined only at the outlet of the control equipment in accordance with 40 C.F.R. § 75.15 (using $SO_2$ CEMS data from only the outlet of the control device).

## VII. PM EMISSION REDUCTIONS AND CONTROLS

### A. Optimization of PM Controls

88. Within 45 days of lodging of this Consent Decree and continuing thereafter, Wisconsin Electric shall continuously operate each Particulate Matter Control Device on its Existing Units to maximize PM emission reductions, consistent with the operational and maintenance limitations of the Units. Specifically, Wisconsin Electric shall, at a minimum: (a) energize each section of the ESP for each Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESPs for each Unit to achieve the greatest possible removal of PM; (c) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; and (d) maintain an ongoing bag leak detection and replacement program to assure optimal operation of each BH.

### B. Upgrade of PM Controls

89. Within 365 days of lodging of this Consent Decree, Wisconsin Electric shall operate each of the ESPs and BHs within the Wisconsin Electric System, except Units 5 and 6 at the Presque Isle Generating Station, to achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU. Presque Isle Unit 5 shall achieve and maintain a PM Emission Rate of 0.030

lb/mmBTU by June 30, 2005 and Presque Isle Unit 6 shall achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU by June 30, 2006.

90. Wisconsin Electric shall continuously operate each ESP and BH in the Wisconsin Electric System at all times that the Unit it serves is combusting coal. Wisconsin Electric shall use good operating practices at all times that the Unit is combusting coal.

C. PM Monitoring

1. PM Stack Tests

91. Beginning in calendar year 2004, and continuing annually thereafter, Wisconsin Electric shall conduct a performance test on each Wisconsin Electric System Unit. The annual stack test requirement imposed on each Wisconsin Electric System Unit by this Paragraph may be satisfied by Wisconsin Electric's stack tests conducted as required by its permits from the States of Michigan and Wisconsin for any year that such stack tests are required under the permits. Wisconsin Electric may perform biennial rather than annual testing provided that (a) two of the most recently completed test results from tests conducted in accordance with Method 5 or Method 17 demonstrate that the particulate matter emissions are equal to or less than a 0.015 lb/mmBTU emission limitation, or (b) the Unit is equipped with a PM CEMS in accordance with Paragraph 96. Wisconsin Electric shall perform annual rather that biennial testing the year immediately following any test result demonstrating that the particulate matter emissions are greater than a 0.015 lb/mmBTU emission limitation.

92. The reference and monitoring methods and procedures for determining compliance with Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17. Use of any particular method shall conform to the EPA

requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48a (b) and (e), or any federally approved SIP method. Wisconsin Electric shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f), and 40 C.F.R. § 60.46a(c). The results of each PM stack test shall be submitted to EPA within 45 days of completion of each test. PM stack tests of the Units at the Presque Isle Generating Station shall also be submitted to the MDEQ within 45 days of completion of each test.

93. The PM Emission Rates established under Paragraph 89 of this Section shall not apply during periods of startup and shutdown or during periods of control equipment or Unit Malfunction, if the Malfunction meets the requirements of the Force Majeure section of this Consent Decree. Periods of startup shall not exceed two hours after any amount of coal is combusted. Periods of shutdown shall only commence when the Unit ceases burning any amount of coal.

2. PM CEMS

94. Wisconsin Electric shall undertake a program to install and operate Continuous Emission Monitoring System for Particulate Matter ("PM CEMS"). Each PM CEMS shall be comprised of a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert results to units of lb/mmBTU. Wisconsin Electric shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in lb/mmBTU. Wisconsin Electric shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

95. No later than one year prior to the deadline to commence operation as set forth in Paragraph 96, Wisconsin Electric shall submit to EPA for review and approval a plan for the installation and certification of each PM CEMS.

96. Wisconsin Electric shall install, certify, and operate PM CEMS on 10 Units, stacks or common stacks in accordance with the following schedule:

| **Unit** | **Deadline to Commence Operation** | **Location** |
|---|---|---|
| Presque Isle Units 1-4 | April 1, 2006 | Common Outlet Flue at Stack |
| Presque Isle Unit 5 | April 1, 2006 | Stack |
| Presque Isle Unit 6 | April 1, 2006 | Stack |
| Presque Isle Units 7-9 | April 1, 2006 | Common Outlet Duct of TOXECON |
| Oak Creek Units 5&6 | April 1, 2005 | Common Stack |
| Oak Creek Unit 7 | April 1, 2005 | Precipitator Outlet Duct |
| Oak Creek Unit 8 | April 1, 2005 | Precipitator Outlet Duct |
| Pleasant Prairie Units 1&2 | April 1, 2005 | Common Stack |
| Valley Unit 1 | April 1, 2006 | Common Stack |
| Valley Unit 2 | April 1, 2006 | Common Stack |

97. Notwithstanding the requirements of Paragraph 96, by April 1, 2005, Wisconsin Electric may install two mercury CEMS, one of which will be installed at Pleasant Prairie Unit 1

or Unit 2, and one of which will be installed at Oak Creek Unit 7 or Unit 8, in lieu of a PM CEMS on Presque Isle Units 1 through 4 and one of the units at Valley.

98. No later than 120 days prior to the deadline to commence operation of each PM CEMS, Wisconsin Electric shall submit to EPA for approval pursuant to Section XIII (Review and Approval of Submittals) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. Following EPA's approval of the protocol, Wisconsin Electric shall thereafter operate each PM CEMS in accordance with the approved protocol.

99. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, Wisconsin Electric may use the criteria set forth in EPA's proposed revisions to Performance Specification 11: Specification and Test Procedures for PM CEMS and Procedure 2: PM CEMS at Stationary Sources (PS 11), as published at 66 Fed. Reg 64176 (December 12, 2001) or other available PM CEMS guidance.

100. No later than 90 days after Wisconsin Electric begins operation of the PM CEMS, Wisconsin Electric shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS plan submitted to and approved by EPA in accordance with Paragraph 95.

101. If after Wisconsin Electric operates the PM CEMS for at least two years, and if the Parties then agree that it is infeasible to continue operating PM CEMS, Wisconsin Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEMS and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Wisconsin Electric shall continue to operate the PM CEMS.

102. Operation of a PM CEMS shall be considered "infeasible" if (a) the PM CEMS cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol; or (b) Wisconsin Electric demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If the United States determines that Wisconsin Electric has demonstrated infeasibility pursuant to this Paragraph, Wisconsin Electric shall be entitled to discontinue operation of and remove the PM CEMS.

3. PM Reporting

103. Following the installation of each PM CEMS, Wisconsin Electric shall begin and continue to report to EPA, pursuant to Section XII, the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour, 24-hour, 30-day, and 365-day rolling average basis in electronic format, as required in Paragraph 94. For the PM CEMS installed at the Presque Isle Generating Station, the above data also shall be reported to the MDEQ.

D. General PM Provisions

104. In determining the PM Emission Rate, Wisconsin Electric shall use the reference methods specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17, using stack tests, or alternative methods that are either promulgated by EPA or requested by Wisconsin Electric and approved by EPA. Wisconsin Electric shall also calculate the PM Emission Rates from annual (or biennial) stack tests in accordance with 40 C.F.R. § 60.8(f). Wisconsin Electric shall also determine PM Emission Rates using PM CEMS consistent with the approved QA/QC protocol.

105. Data from the PM CEMS shall be used by Wisconsin Electric, at a minimum, to monitor progress in reducing PM emissions. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

## VIII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

106. For any and all actions taken by Wisconsin Electric to comply with the requirements of this Consent Decree, including but not limited to the upgrade of ESPs and BHs, the installation of FGDs, SCRs, or equivalent control devices approved under this Consent Decree, the re-powering of certain units, the retirement of certain units, and the reduction of emissions to satisfy annual emission tonnage limitations, any emission reductions generated shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs. Notwithstanding the preceding sentence, Wisconsin Electric may use any creditable contemporaneous emission decreases of Volatile Organic Compounds ("VOCs") generated under this Consent Decree for the purpose of obtaining a netting credit for VOCs under the Clean Air Act's Nonattainment NSR and PSD programs.

107. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Decree from being considered by the State of Michigan and EPA as creditable contemporaneous emission decreases for the purpose of attainment demonstrations

submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS and PSD increment consumption.

## IX. ENVIRONMENTAL PROJECTS

108. Wisconsin Electric, in cooperation with the United States Department of Energy ("DOE") and potentially other parties, shall design, construct, operate and analyze the first full scale TOXECON with activated carbon injection with the goal of achieving a 90% removal of all species of mercury ("the TOXECON Project"). The TOXECON Project will be implemented at Units 7, 8, and 9 of Wisconsin Electric's Presque Isle Generating Station.

109. At least six months before it plans to commence implementation of the TOXECON Project, Wisconsin Electric shall submit to the Plaintiffs for review and approval pursuant to Section XIII of this Consent Decree a plan for the implementation of the TOXECON Project, including the date by which Wisconsin Electric will commence design and construction of the Project, and the date by which Wisconsin Electric will complete the Project. To the extent that any change to the TOXECON Project may be required, Wisconsin Electric shall notify the Plaintiffs of such change within 60 days of becoming aware a change is necessary. Wisconsin Electric shall implement the TOXECON Project in compliance with the schedules and terms of this Consent Decree and the plans for such Project approved under this Decree.

110. For purposes of this Consent Decree, in performing the TOXECON Project, Wisconsin Electric shall, prior to December 31, 2006, spend no less than $20 million, and shall not be required to spend more than $25 million, in Project Dollars (measured in calendar year 2003 constant dollars). Wisconsin Electric shall maintain all documents required by Generally

Accepted Accounting Principles to substantiate the Project Dollars spent by Wisconsin Electric, and shall provide copies of these documents to the Plaintiffs within 30 days of a request by one or more of the Plaintiffs for these documents.

111. All plans and reports prepared by Wisconsin Electric pursuant to the requirements of this Section in this Consent Decree shall be publicly available without charge, subject to the limitations contained in Paragraph 179.

112. Wisconsin Electric shall certify, as part of each plan submitted to the Plaintiffs for any Project, that it is unaware of any person required by law, other than this Consent Decree, to perform the Project described in the plan.

113. Wisconsin Electric shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

114. Within 60 days following the completion of the TOXECON Project, Wisconsin Electric shall submit to the EPA and the MDEQ a report that documents the date that the Project was completed, Wisconsin Electric's results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Wisconsin Electric in implementing the Project.

115. Following completion of the TOXECON Project, Wisconsin Electric shall maintain the baghouse component of the TOXECON in the flue gas stream regardless of the results of the demonstration project. If Wisconsin Electric determines that the demonstration project has removed reasonable levels of mercury and is operationally viable, Wisconsin Electric shall also continue sorbent injection for mercury control.

116. Wisconsin Electric shall not financially benefit from the sale or transfer of the TOXECON technology or the collection or distribution of information collected during this demonstration project.

117. Wisconsin Electric shall provide the United States and the MDEQ with semi-annual updates concerning the progress of the TOXECON Project. Wisconsin Electric also shall make information concerning the performance of the TOXECON Project available to the public in an expeditious matter, consistent with DOE's requirements concerning the disclosure of project information and subject to the limitations contained in Paragraph 179. Such information disclosure shall include, but not be limited to, release of periodic progress reports, clearly identifying demonstrated removal efficiencies of mercury and other pollutants, sorbent injection rates and cost effectiveness. In addition, periodic technology transfer open houses and plant tours shall be scheduled, consistent with DOE's requirements for disclosure of project information and subject to the limitations contained in Paragraph 179.

## X. CIVIL PENALTY AND FINE

118. Within thirty (30) calendar days of entry of this Consent Decree, Wisconsin Electric shall pay to the United States a civil penalty in the amount of $3.1 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2003V00451 and DOJ Case Number 90-5-2-1-07493 and the civil action case name and case number of this action, with notice given to the Plaintiff, in accordance with Section XX (Notices) of this Consent Decree. The costs of such EFT shall be Wisconsin Electric's responsibility. Payment shall be made in accordance with instructions provided to Wisconsin

Electric by the Financial Litigation Unit of the U.S. Attorney's Office for the Eastern District of Wisconsin. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, Wisconsin Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1-07493, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 181 (Notice) of this Consent Decree.

119. Failure to timely pay the civil penalty shall subject Wisconsin Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Wisconsin Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

120. Within thirty (30) calendar days of entry of this Consent Decree, Wisconsin Electric shall pay to the State of Michigan a civil fine in the amount of $100,000. Payment shall be made in the form of a certified check or cashier's check, and be payable to the "State of Michigan." Payment shall be sent to the Michigan Department of Environmental Quality, Cashier's Office, P.O. Box 30657, 525 West Allegan Street, Lansing, MI 48909. To ensure proper credit, the check must reference *United States, et. al. v. Wisconsin Electric Power Company*, the Civil Action Number and the Air Quality Division Account Number 1072.

121. To ensure timely payment of the civil fine in Paragraph 120, Wisconsin Electric shall pay interest to the State of Michigan if it fails to make a complete or timely payment to the State of Michigan under this Consent Decree. Pursuant to MCL § 324.6013(6), the interest shall be determined at an annual rate that is equal to one percent (1%) plus the average interest rate

paid at auctions of the 5-year United States treasury notes during the six months immediately preceding July 1 and January 1, as certified by the State treasurer, and compounded annually. The interest shall be calculated on the full amount of the civil fine due as principal, calculated from the due date specified in this Consent Decree until the date that the delinquent payment is finally paid in full.

122. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

## XI. RESOLUTION OF CLAIMS

### A. RESOLUTION OF CIVIL CLAIMS

123. U.S. Claims Based on Modifications Occurring Before the Lodging of Decree. Entry of this Decree shall resolve all civil claims of the United States under either: (i) Parts C or D of Subchapter I of the Clean Air Act or (ii) 40 C.F.R. Section 60.14, that arose from any modifications that commenced at any Wisconsin Electric System Unit prior to the date of lodging of this Decree, including but not limited to those modifications alleged in the Complaint filed by the United States in this civil action.

124. U.S. Claims Based on Modifications After the Lodging of Decree. Entry of this Decree also shall resolve all civil claims of the United States for pollutants regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated as of the date of lodging of this Decree, where such claims are based on a modification completed before December 31, 2015 and:

(a) commenced at any Wisconsin Electric System Unit after lodging of this Decree; or

(b) that this Consent Decree expressly directs Wisconsin Electric to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

125. Reopener. The resolution of the civil claims of the United States provided by this Subsection is subject to the provisions of Subsection B of this Section.

126. State of Michigan Claims Based on Modifications Occurring Before the Lodging of the Decree. Entry of this Decree shall resolve all civil claims of the State of Michigan under (i) Part C of Subchapter I of the Clean Air Act and (ii) Section 5505 of Part 55 of NREPA, MCL § 324.5505, that arose from any modifications that commenced at any Unit at Wisconsin Electric's Presque Isle Generating Station in Marquette, Michigan prior to the date of lodging of this Decree, including but not limited to those modifications alleged in the Complaint filed by the State of Michigan in this action.

127. State of Michigan Claims Based on Modifications After the Lodging of Decree. Entry of this Decree also shall resolve all civil claims of the State of Michigan for pollutants regulated under (i) Part C of Subchapter I of the Clean Air Act and regulations promulgated as of the date of lodging of this Decree and (ii) Section 5505 of Part 55 of NREPA, MCL § 324.5505, where such claims are based on a modification completed before December 31, 2015 and:

(a) commenced at any Unit at Wisconsin Electric's Presque Isle Generating Plant after lodging of this Decree; or

(b) that this Consent Decree expressly directs Wisconsin Electric to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

128. Reopener. The resolution of the civil claims of the State of Michigan provided by this Subsection is subject to the provisions of Subsection B of this Section.

B. PURSUIT OF PLAINTIFFS' CIVIL CLAIMS OTHERWISE RESOLVED

129. Bases for Pursuing Resolved Claims Across Wisconsin Electric System. If Wisconsin Electric violates Paragraph 63 (System-wide $NO_x$ Rolling Tonnage Limits), Paragraph 62 (System-wide $NO_x$ Rolling Average Emission Rate), Paragraph 77 (System-wide Rolling $SO_2$ Tonnage Limits), Paragraph 76 (System-wide Rolling Average $SO_2$ Emission Rates), or Paragraph 85 (Fuel Limitation), or fails by more than ninety days to complete installation and commence operation of any emission control device required pursuant to Paragraphs 58 or 73; or fails by more than ninety days to control or retire and permanently cease to operate Wisconsin Electric System Units pursuant to Paragraph 57, then the United States may pursue any claim at any Wisconsin Electric System Unit that has otherwise been resolved under Subsection A of this Section, subject to (A) and (B) below, and the State of Michigan may pursue any claim at any Unit at the Presque Isle Generating Station that has otherwise been resolved under Subsection A of this Section, subject to (A) and (B) below.

(A) For any claims based on modifications undertaken at an Other Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced within the five years preceding the violation or failure specified in this Paragraph.

(B) For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced (i) after lodging of the Consent Decree and (ii) within the five years preceding the violation or failure specified in this Paragraph.

130. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to Improved Units, the United States may also pursue claims arising from a modification (or collection of modifications) at an Improved Unit that have otherwise been resolved under Section XI, Subsection A, and the State of Michigan may also pursue claims arising from a modification (or collection of modifications) at an Improved Unit at the Presque Isle Generating Station that have otherwise been resolved under Section XI, Subsection A, if the modification (or collection of modifications) at the Improved Unit on which such claim is based (i) was commenced after lodging of this Consent Decree, and (ii) individually (or collectively) increased the maximum hourly emission rate of that Unit for $NO_x$ or $SO_2$ (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

131. Additional Bases for Pursuing Resolved Claims for Modifications at an Other Unit. Solely with respect to Other Units, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that have otherwise been resolved under Section XI, Subsection A, and the State of Michigan may also pursue claims arising from a modification (or collection of modifications) at an Other Unit at the Presque Isle Generating Station that have otherwise been resolved under Section XI, Subsection A, if the modification (or collection of modifications) on which the claim is based was commenced within the five years preceding any of the following events:

(A) a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree increases the maximum hourly emission rate for such Other Unit for the relevant pollutant ($NO_x$ or $SO_2$) as measured by 40 C.F.R. § 60.14(b) and (h);

(B) the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the capacity numbers included in Paragraph 56) during any of the following five year periods: January 1, 2006 through December 31, 2010; January 1, 2011 through December 31, 2015. For the period from the date of lodging of this Decree through December 31, 2005, the $125/KW limit shall be pro-rated to include only that portion of the five-year period (January 1, 2000 through December 31, 2005) following the date of lodging of this Decree. (Capital Expenditures shall be measured in calendar year 2002 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

(C) a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree results in an emissions increase of $NO_x$ and/or $SO_2$ at such Other Unit, and such increase:

(1) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603;

(2) causes or contributes to violation of a National Ambient Air Quality Standard ("NAAQS") in any Air Quality Control Area that is in attainment with that NAAQS;

(3) causes or contributes to violation of a PSD increment; or

(4) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area.

(D) Solely for purposes of Paragraph 131, Subparagraph (C), the determination of whether there was an emissions increase must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other Wisconsin Electric System Units. In addition, an emissions increase shall be deemed to have occurred at an Other Unit if the annual emissions of the relevant pollutant ($NO_x$ or $SO_2$) from the plant at which such modification(s) occurred exceed the Baseline for that plant.

(E) The introduction of any new or changed National Ambient Air Quality Standard shall not, standing alone, provide the showing needed under Paragraph 131, Subparagraphs (C)(2) or (C)(3), to pursue any claim for a modification at an Other Unit resolved under Subsection A of this Section.

## XII. PERIODIC REPORTING

132. Within 180 days after each date established by this Consent Decree for Wisconsin Electric to achieve and maintain a certain Emission Rate or Removal Efficiency at any Wisconsin Electric System Unit, Wisconsin Electric shall conduct performance tests that demonstrate compliance with the Emission Rate or Removal Efficiency required by this Consent Decree. Within 45 days of each such performance test, Wisconsin Electric shall submit the results of the performance test to EPA at the addresses specified in Section XX (Notices) of this Consent Decree. For performance tests of the Units at the Presque Isle Generating Station, Wisconsin Electric shall also submit the results to the MDEQ at the addresses specified in Section XX (Notices) of this Consent Decree.

133. Beginning thirty days after the end of the first full calendar quarter following the entry of this Consent Decree or December 31, 2003, whichever is later, continuing on a semi-

annual basis until December 31, 2015, and in addition to any other express reporting requirement in this Consent Decree, Wisconsin Electric shall submit to EPA and the MDEQ a progress report.

134. The progress report shall contain the following information:

a. all information necessary to determine compliance with this Consent Decree;

b. all information relating to emission allowances and credits that Wisconsin Electric claims to have generated in accordance with Paragraphs 69 and 84 by compliance beyond the requirements of this Consent Decree; and

c. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by Wisconsin Electric to mitigate such delay.

135. In any periodic progress report submitted pursuant to this Section, Wisconsin Electric may incorporate by reference information previously submitted under its Title V permitting requirements, provided that Wisconsin Electric attaches the Title V permit report and provides a specific reference to the provisions of the Title V permit report that are responsive to the information sought in the periodic progress report.

136. In addition to the progress reports required pursuant to this Section, Wisconsin Electric shall provide a written report to EPA of any violation of the requirements of this Consent Decree, including exceedances of required Emission Rates, removal efficiencies, and Unit-Specific and System-wide Rolling Average Emission Rate and Rolling Tonnage limits,

within 10 business days of when Wisconsin Electric knew or should have known of any such violation. Wisconsin Electric shall also provide such a written report to the MDEQ of any violation of the System-wide Rolling Average Emission Rate and Rolling Tonnage limits and any Unit-specific requirements applicable to the Units at the Presque Isle Generating Station, within 10 business days of when Wisconsin Electric knew or should have known of any such violation. In this report, Wisconsin Electric shall explain the cause or causes of the violation and all measures taken or to be taken by Wisconsin Electric to prevent such violations in the future.

137. Each Wisconsin Electric report shall be signed by Wisconsin Electric's Vice President Environmental, or, in his or her absence, General Counsel, or higher ranking official, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

138. If any allowances are surrendered to any third party pursuant to Section VI.C of this Consent Decree, the third party's certification shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that,_____ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for making false, inaccurate, or incomplete information to the United States.

## XIII. REVIEW AND APPROVAL OF SUBMITTALS

139. Wisconsin Electric shall submit and complete each plan, report, or other item to the Plaintiffs whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA, in consultation with the MDEQ to the extent the report is provided to the MDEQ under this Consent Decree, may approve the submittal or decline to approve it and provide written comments. Within 60 days of receiving written comments from EPA, Wisconsin Electric shall either: (i) alter the submittal consistent with the written comments and provide the revised submittal for final approval to EPA and the MDEQ, to the extent the submittal is provided to MDEQ under this Consent Decree, if called for in this Consent Decree; or (ii) submit the matter for dispute resolution, including the period of informal negotiations, under Section XVI (Dispute Resolution) of this Consent Decree.

140. Upon receipt of the United States' final approval of the submittal and the State of Michigan's final approval, if applicable, or upon completion of the submittal pursuant to dispute resolution, Wisconsin Electric shall implement the submittal in accordance with the approved submittal.

## XIV. STIPULATED PENALTIES

141. For any failure by Wisconsin Electric to comply with the terms of this Consent Decree, and subject to the provisions of Sections XV (Force Majeure) and XVI (Dispute Resolution), Wisconsin Electric shall pay, within 30 days after written demand to Wisconsin Electric by the United States the following stipulated penalties to EPA:

| **Consent Decree Violation** | **Stipulated Penalty (Per day per violation, unless otherwise specified)** |
|---|---|
| a. Failure to pay the civil penalty as specified in Section X (Civil Penalty) of this Consent Decree | $10,000 |

| | |
|---|---|
| b. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is less than 5% in excess of the limits set forth in this Consent Decree | $2,500 |
| c. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree | $5,000 |
| d. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree | $10,000 |
| e. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is less than 5% in excess of the limits set forth in this Consent Decree | $2,500 per month |
| f. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree | $5,000 per month |
| g. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree | $10,000 per month |
| h. Failure to meet the System-wide 12-month Rolling $SO_2$ and $NO_x$ Tonnage Limits as set out in Paragraphs 63 and 77 or any other the 12-month rolling tonnage limitation | $5,000 per ton per month for the first 100 tons over the limit, and $10,000 per ton per month for each additional ton over the limit |

| | |
|---|---|
| i. Failure to install, commence operation, or continue operation of the $NO_x$, $SO_2$, and PM pollution control devices on any Unit, or failure to retire a Unit | $10,000 during the first 30 days, $27,500 thereafter |
| j. Failure to meet the fuel use limitations at a Unit, as required by Paragraph 85 | $10,000 |
| k. Failure to install or operate CEMS as required in Paragraph 94, subject to Paragraph 102 | $1,000 |
| l. Failure to conduct annual or biennial performance tests of PM emissions, as required in Paragraph 91 | $1,000 |
| m. Failure to apply for the permits required by Paragraphs 172-174 | $1,000 |
| n. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree | $750 for the first ten days, $1,000 thereafter. |
| o. Using, selling, or transferring $SO_2$ Allowances, except as permitted by Paragraphs 79, 80 and 84 | (a) three times the market value of the improperly used allowance, as measured at the time of the improper use, plus (b) the surrender, pursuant to the procedures set forth in Paragraphs 79 through 81 of this Decree, of $SO_2$ Allowances in an amount equal to the $SO_2$ Allowances used, sold, or transferred in violation of the Decree |
| p. Using, selling or transferring NOx allowances or credits except as permitted under Paragraph 67-69 | (a) three times the market value of the improperly used allowance, as measured at the time of the improper use, plus (b) the surrender, pursuant to the procedures set forth in Section XII (Periodic Reporting) of this Decree, of $NO_x$ allowances or credits in an amount equal to the $NO_x$ allowances or credits used, sold, or transferred in violation of the Decree |

| | |
|---|---|
| q. Failure to surrender an $SO_2$ Allowance in accordance with Paragraph 80 | (a) $27,500 plus (b) $1,000 per $SO_2$ Allowance |
| r. Failure to demonstrate the third-party surrender of an $SO_2$ Allowance in accordance with Paragraph 81 | $2,500 |
| s. Failure to undertake and complete any of the Environmental Projects in compliance with Section IX (Environmental Projects) | $1,000 for the first 30 days, $5,000 thereafter |
| t. Any other violation of this Consent Decree | $1,000 |

142. Violation of an Emission Rate or Removal Efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Violation of System-wide 12-Month Rolling Average Emission Rates, System-wide 12-Month Rolling Tonnage Limitations or any other 12-month rolling limitation is a violation each month on which the average is based.

143. Where a violation of a 30-Day Rolling Average Emission Rate or Removal Efficiency (for the same pollutant and from the same source) recurs within periods less than 30 days, Wisconsin Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

144. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Nothing herein shall prevent the simultaneous accrual of separate penalties for separate violations of this Consent Decree.

145. Wisconsin Electric shall pay all stipulated penalties to the United States, in the manner set forth below in Paragraph 147, within 30 days of any violation of this Consent Decree, and shall continue to make such payments every 30 days thereafter until the violation(s) no

longer continues, unless Wisconsin Electric elects within 20 days of the violation to dispute the accrual of stipulated penalties in accordance with the provisions in Section XVI (Dispute Resolution) of this Consent Decree.

146. Penalties shall continue to accrue as provided in accordance with Paragraph 144 during any dispute, with interest on accrued penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of any Plaintiff that is not appealed to the Court, accrued penalties determined to be owing, together with accrued interest, shall be paid to the United States within thirty (30) days of the effective date of the agreement or the receipt of EPA's decision or order;

b. If the dispute is appealed to the Court and any Plaintiff prevails in whole or in part, Wisconsin Electric shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued penalties determined by the Court to be owing, together with accrued interest, except as provided in Subparagraph c, below;

c. If the District Court's decision is appealed by any Party, Wisconsin Electric shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued penalties determined to be owing to the United States, together with accrued interest.

147. All stipulated penalties must be paid within thirty (30) days of the date payable, and payment shall be made in the manner set forth in Section X of this Consent Decree (Civil Penalty).

148. Should Wisconsin Electric fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

149. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to any Plaintiff by reason of Wisconsin Electric's failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree also provides for payment of a stipulated penalty, Wisconsin Electric shall be allowed a credit for stipulated penalties paid against any statutory penalties imposed for such violation.

## XV. FORCE MAJEURE

150. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of Wisconsin Electric, its contractors, or any entity controlled by Wisconsin Electric that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Wisconsin Electric's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

151. Notice. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Wisconsin Electric intends to assert a claim of Force Majeure, Wisconsin Electric shall notify the United States in writing as soon as practicable, but in no event later than fourteen (14) business days

following the date Wisconsin Electric first knew, or by the exercise of due diligence should have known, that the Force Majeure Event caused or may cause such delay or violation. If the event on which the Force Majeure claim is based occurred at the Presque Isle Generating Station, Wisconsin Electric also shall provide the State of Michigan with notice. In this notice, Wisconsin Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by Wisconsin Electric to prevent or minimize the delay or violation, the schedule by which Wisconsin Electric proposes to implement those measures, and Wisconsin Electric's rationale for attributing a delay or violation to a Force Majeure Event. Wisconsin Electric shall adopt all reasonable measures to avoid or minimize such delays or violations. Wisconsin Electric shall be deemed to know of any circumstance of which Wisconsin Electric, its contractors, or any entity controlled by Wisconsin Electric knew or should have known.

152. Failure to Give Notice. If Wisconsin Electric fails to comply with the notice requirements of this Section, the United States and, if the event on which the Force Majeure claim is based occurred at the Presque Isle Generating Station, the State of Michigan, may void Wisconsin Electric's claim for Force Majeure as to the specific event for which Wisconsin Electric has failed to comply with such notice requirement.

153. Plaintiffs' Response. The United States and, if the event on which the Force Majeure claim is based occurred at the Presque Isle Generating Station, the State of Michigan, shall notify Wisconsin Electric in writing regarding Wisconsin Electric's claim of Force Majeure within (20) twenty business days of receipt of the notice provided under Paragraph 151. To the

extent the Force Majeure claim involves the Presque Isle Generating Station, the United States shall consult with the State of Michigan prior to notifying Wisconsin Electric regarding its claim of Force Majeure. If the United States and, if the event on which the Force Majeure claim is based occurred at the Presque Isle Generating Station, the State of Michigan, agrees that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement by a period not to exceed the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXIV of this Consent Decree (Modification).

154. Disagreement. If the United States and, if the event on which the Force Majeure claim is based occurred at the Presque Isle Generating Station, the State of Michigan, does not accept Wisconsin Electric's claim of Force Majeure, the matter shall be resolved in accordance with Section XVI of this Consent Decree (Dispute Resolution).

155. Burden of Proof. In any dispute regarding Force Majeure, Wisconsin Electric shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. Wisconsin Electric shall also bear the burden of proving that Wisconsin Electric gave the notice required by this Section and the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

156. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Wisconsin Electric's obligations under this Consent Decree shall not constitute a Force Majeure Event.

157. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Wisconsin Electric's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; natural gas and gas transportation availability delay; acts of God; acts of war or terrorism; and orders by a government official, government agency, or other regulatory body acting under and authorized by applicable law that directs Wisconsin Electric to supply electricity in response to a system-wide (state-wide or regional) emergency. Depending upon the circumstances and Wisconsin Electric's response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of Wisconsin Electric and Wisconsin Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting in an expeditious fashion appeals of any allegedly unlawful terms and conditions imposed by the permitting authority.

158. As part of the resolution of any matter submitted to this Court under this Section, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay

in the work that occurred as a result of any delay agreed to by the Plaintiffs or approved by this Court. Wisconsin Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

## XVI. DISPUTE RESOLUTION

159. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, except as provided in either this Section (Dispute Resolution) or Section XV (Force Majeure) of this Consent Decree, provided that the Party making such application has first made a good faith attempt to resolve the matter with the other Parties.

160. The dispute resolution procedure required herein shall be invoked by one Party to this Consent Decree giving written notice to the other Parties to this Consent Decree advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Parties receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

161. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the disputing Parties' representatives unless they agree to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their

dispute to a mutually-agreed-upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period.

162. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide Wisconsin Electric with a written summary of their position regarding the dispute. The written position provided by the Plaintiffs shall be considered binding unless, within forty-five (45) calendar days thereafter, Wisconsin Electric seeks judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) calendar days of filing.

163. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the Parties to the dispute.

164. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

165. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Wisconsin Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

166. As to disputes arising under Section VII of this Consent Decree (PM Emission Reductions and Controls), the Court shall sustain the position of the Plaintiffs as to the feasibility

of obtaining accurate and reliable data from the PM CEMS that Wisconsin Electric is to install pursuant to Paragraph 96, unless Wisconsin Electric demonstrates that the position of the Plaintiffs is arbitrary or capricious. The Court shall decide all other disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 162, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

## XVII. EMISSIONS LIMITATIONS ON THE SOUTH OAK CREEK AND ELM ROAD GENERATING STATIONS

167. Wisconsin Electric has submitted an application for a PSD Permit for the construction of proposed new coal-fired generating Units, which if approved will be known as the Elm Road Generating Station. If, at any time after the date of lodging of this Consent Decree, one or more of the new units at the proposed Elm Road Generating Station is approved and constructed, Wisconsin Electric shall limit the combined emissions of $SO_2$, $NO_x$, PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from both its South Oak Creek Generating Station and its Elm Road Generating Station to 38,400 tons per year, collectively. This emission limitation is based on actual or calculated emissions of $SO_2$, $NO_{x,}$ PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from the existing units at South Oak Creek Generating Station in calendar year 2000. Compliance with this emission limitation shall be demonstrated on a 12-month rolling average. The emission limitation shall be included in the Title V operating permit issued to the South Oak Creek Generating Station and the Elm Road Generating Station, if approved and constructed.

## XVIII. PERMITS

168. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Wisconsin Electric to secure a permit to authorize construction or operation of any device, including all preconstruction, construction, and operating permits required under state law, Wisconsin Electric shall make such application in a timely manner. EPA and the MDEQ will use their best efforts to expeditiously review all permit applications submitted pursuant to this Consent Decree.

169. Notwithstanding the previous paragraph, nothing in this Consent Decree shall be construed to require Wisconsin Electric to apply for or obtain a PSD or Nonattainment NSR permit for physical changes or changes in the method of operation that would give rise to claims resolved by Section XI (Resolution of Claims) of this Consent Decree.

170. When permits are required as described in Paragraph 168, Wisconsin Electric shall complete and submit applications for such permits to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Any failure by Wisconsin Electric to submit a timely permit application for any Unit in the Wisconsin Electric System shall bar any use by Wisconsin Electric of Section XV (Force Majeure), where a Force Majeure claim is based on permitting delays.

171. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be directly enforceable under this Decree, although any term or limit established by or under this Decree shall be enforceable under this Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXVIII (Conditional Termination of Enforcement Under Decree).

172. Within ninety (90) days of entry of this Consent Decree, Wisconsin Electric shall amend any applicable Title V permit application, or apply for amendments of its Title V permits, to include a schedule for all performance, operational, maintenance, and control technology requirements established by this Consent Decree, including, but not limited to, Emission Rates, removal efficiencies, limits on fuel use, and the requirement in Paragraph 80 pertaining to surrender of $SO_2$ allowances.

173. Within one year from the commencement of operation of each pollution control device to be installed or upgraded on an Improved Unit under this Consent Decree, Wisconsin Electric shall apply to modify its Title V permit for the generating plant where such device is installed to reflect all new requirements applicable to that plant, including, but not limited to any applicable 30-Day Rolling Average Emission Rate or Removal Efficiency.

174. Prior to January 1, 2015, Wisconsin Electric shall apply to amend the Title V permit for each plant in the Wisconsin Electric System to include specific Emission Rates or tonnage limitations as described below. Wisconsin Electric shall be in compliance with this requirement if, by January 1, 2015, it has applied to amend each such Title V permit to include Emissions Rate limitations applicable to Improved Units and tonnage limitations applicable to plants with Other Units. Improved Units shall not exceed a 12-Month Rolling Average Emission Rate for NOx of 0.080 lb/mmBTU and a 12-Month Rolling Average Emission Rate for $SO_2$ of 0.080 lb/mmBTU or a Removal Efficiency of 96% for $SO_2$. The plants with Other Units shall meet the following Plant-specific 12-Month Rolling Tonnage:

| **Plant** | **$NO_x$** | **$SO_2$** |
|---|---|---|
| Valley | 3, 989 | 9,973 |

| | | |
|---|---|---|
| Presque Isle | 7,376 | 17, 257 |

175. Wisconsin Electric shall provide the United States with a copy of each application to amend its Title V permit, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

176. If Wisconsin Electric sells or transfers to a Third Party Purchaser part or all of its ownership interest in a Unit in the Wisconsin Electric System, Wisconsin Electric shall comply with the requirements of Paragraph 174 with regard to that Unit, prior to any such sale or transfer unless, following any such sale or transfer, Wisconsin Electric remains the holder of the Title V permit for such facility. For purposes of this Paragraph and Section XXI, "Third Party Purchaser" refers to an entity unrelated to Wisconsin Electric, WEC or W.E. Power that may acquire an ownership interest in one or more of the Units in the Wisconsin Electric System.

## XIX. INFORMATION COLLECTION AND RETENTION

177. Any authorized representative of the United States or Permitting State Agency, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the Wisconsin Electric System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the Plaintiffs in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by Wisconsin Electric or its representatives, contractors, or consultants; and

d. assessing Wisconsin Electric's compliance with this Consent Decree.

178. Wisconsin Electric shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors' or agents' possession or control, and that directly relate to Wisconsin Electric's performance of its obligations under this Consent Decree for the following periods: (a) until December 31, 2020 for records concerning physical or operational changes undertaken in accordance with Paragraph 124 (Resolution of U.S. Claims Based On Modifications after Lodging of the Decree) and Paragraph 127 (Resolution of State of Michigan Claims based on Modifications after Lodging of the Decree) of this Consent Decree; and (b) until December 31, 2017 for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

179. All information and documents submitted by Wisconsin Electric pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless (a) the information and documents are subject to legal privileges or protection or (b) Wisconsin Electric claims and substantiates that the information and documents contain confidential business information in accordance with 40 C.F.R. Part 2.

180. Nothing in this Consent Decree shall limit the authority of the Plaintiffs to conduct tests and inspections at Wisconsin Electric's facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

## XX. NOTICES

181. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06965

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region V
77 West Jackson Blvd.
Chicago, Illinois 60604-3590

As to the State of Michigan:

Chief, Environment, Natural Resources and Agricultural Division
Michigan Department of Attorney General
P.O. Box 30217
Lansing, MI 48909

and

Chief, Air Quality Division
Michigan Department of Environmental Quality
525 W. Allegan Street
Lansing, MI 48909

As to Wisconsin Electric:

Vice President Environmental
Wisconsin Electric Power Company

231 W. Michigan Street
Milwaukee, Wisconsin 53203

and

General Counsel
Wisconsin Electric Power Company
231 W. Michigan Street
Milwaukee, Wisconsin 53203

182. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or by certified or registered mail, return receipt requested; (b) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked. All notifications, communications, and submissions made by electronic means shall be electronically signed and certified, and shall be deemed submitted on the date that Wisconsin Electric receives written acknowledgment of receipt of such transmission.

183. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Party with a notice setting forth such new notice recipient or address.

## XXI. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

184. If Wisconsin Electric proposes to sell or transfer part or all of its ownership interest in any Existing Unit ("Ownership Interest") to an entity unrelated to Wisconsin Electric, WEC or W.E. Power (Third Party Purchaser), it shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the United States pursuant to Section XX (Notices) at least sixty (60)

days before such proposed sale or transfer. To the extent that a proposed sale or transfer in ownership interests involves one of more of the Units at the Presque Isle Generating Station, Wisconsin Electric also shall provide written notification to the State of Michigan at least sixty (60) days before such proposed sale or transfer.

185. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and the Plaintiffs have executed, and the Court has approved, a modification pursuant to Section XXIV (Modification) of this Consent Decree making the Third Party Purchaser a party defendant to this Consent Decree and jointly and severally liable with Wisconsin Electric for all the requirements of this Decree that may be applicable to the transferred or purchased Ownership Interests, including joint and several liability with Wisconsin Electric for all requirements specific to the Existing Unit, as well as all requirements in this Consent Decree that are not specific to these Existing Units, except as provided in Paragraph 187.

186. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between Wisconsin Electric and any Third Party Purchaser as long the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between Wisconsin Electric and any Third Party Purchaser of Ownership Interests – of the burdens of compliance with this Decree, provided that both Wisconsin Electric and such Third Party Purchaser shall remain jointly and severally liable to the Plaintiffs for the obligations of the Decree applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 187.

187. To the extent that a proposed sale or transfer in ownership interests involves one of more of the Units at the Presque Isle Generating Station, the United States shall consult with the MDEQ with regard to any proposed modification to the Consent Decree under this Section XXI. If the United States, after consultation with the State of Michigan where applicable, agrees, the United States, the State of Michigan, Wisconsin Electric, and the Third Party Purchaser that has become a party defendant to this Consent Decree pursuant to Paragraph 185, may execute a modification that relieves Wisconsin Electric of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, Wisconsin Electric may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections IX (Environmental Projects) and X (Civil Penalty). Wisconsin Electric may propose and the United States, in consultation with the State of Michigan where applicable, may agree to restrict the scope of joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the Unit, to the extent such obligations may be adequately separated in an enforceable manner.

## XXII. EFFECTIVE DATE

188. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

## XXIII. RETENTION OF JURISDICTION

189. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent

Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

## XXIV. MODIFICATION

190. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by all Parties. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

## XXV. GENERAL PROVISIONS

191. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations.

192. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

193. In any subsequent administrative or judicial action initiated by the United States or the State of Michigan for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Wisconsin Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case;

provided, however, that nothing in this Paragraph is intended to affect the validity of Section XI (Resolution of Claims).

194. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Wisconsin Electric of its obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section XI (Resolution of Claims) of this Consent Decree, nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

195. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree, and, except as otherwise provided in this Decree, every other term used in this Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Decree what such term means under the Act or those implementing regulations.

196. Nothing in this Consent Decree alters or waives any applicable law (including but not limited to, any defenses, entitlements, or clarifications related to the Credible Evidence Rule (62 Fed. Reg. 8314 (Feb. 27, 1997))), concerning the use of data for any purpose under the Act, generated by the reference methods specified herein or otherwise.

197. Each limit and/or other requirement established by or under this Decree is a separate, independent requirement.

198. Performance standards, emissions limits, and other quantitative standards set by or under this Decree must be met to the number of significant digits in which the standard or limit is expressed. Thus, for example, an Emission Rate of 0.100 is not met if the actual

Emission Rate is 0.101. Wisconsin Electric shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the second significant digit, depending upon whether the limit is expressed to two or three significant digits. Thus, for example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Wisconsin Electric shall collect and report data to the number of significant digits in which the standard or limit is expressed. As otherwise applicable and unless this Decree expressly directs otherwise, the calculation and measurement procedures established under 40 C.F.R. Parts 75 and 76 apply to the measurement and calculation of $NO_x$ and $SO_2$ under this Decree.

199. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

200. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, or understanding, or promise constitutes any part of this Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

201. Each Party to this action shall bear its own costs and attorneys' fees.

## XXVI. SIGNATORIES AND SERVICE

202. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

203. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

204. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

## XXVII. PUBLIC COMMENT

205. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. Wisconsin Electric shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified Wisconsin Electric, in writing, that the United States no longer supports entry of the Consent Decree.

## XXVIII. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

206. Termination as to Completed Tasks. As soon as Wisconsin Electric completes a construction project or any other requirement of this Consent Decree that is not ongoing or

recurring, Wisconsin Electric may seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

207. Conditional Termination of Enforcement Through the Consent Decree. Once Wisconsin Electric:

(A) believes that it has successfully completed and commences successful operation of all pollution controls required by this Decree;

(B) has obtained final Title V permits (a) as required by the terms of this Consent Decree; (b) that cover all Units in this Consent Decree; and (c) that include as enforceable permit terms all of the Unit performance and other requirements required by Section XVIII (Permits); and

(C) certifies that the date is later than December 31, 2015;

then Wisconsin Electric may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of Wisconsin Electric's certification, then, for any violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

208. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 207, if enforcement of a provision in this Decree cannot be pursued by a party under the applicable Title V permit, or if a Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Decree at any time.

## XXIX. FINAL JUDGMENT

209. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment between the Plaintiffs and Wisconsin Electric.

SO ORDERED, THIS _____ DAY OF _____, 2003.

_____
THE HONORABLE CHARLES N. CLEVERT, JR.
UNITED STATES DISTRICT COURT JUDGE

**FOR THE UNITED STATES OF AMERICA:**

_____
KELLY A. JOHNSON
Principal Deputy Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

_____
NICOLE VEILLEUX
ARNOLD ROSENTHAL
Trial Attorneys
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice

_____

MATTHEW V. RICHMOND
Chief, Civil Division
Eastern District of Wisconsin
United States Department of Justice

_____
JOHN PETER SUAREZ
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

_____
BRUCE C. BUCKHEIT
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

_____
EDWARD MESSINA
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

_____

THOMAS SKINNER
Regional Administrator
Region 5
United States Environmental Protection Agency

**FOR WISCONSIN ELECTRIC:**

_____

RICHARD R. GRIGG
President and Chief Operating Officer
Wisconsin Electric Power Company

**FOR THE STATE OF MICHIGAN**:

MICHAEL A. COX
Attorney General

By: _____
NEIL D. GORDON
Assistant Attorney General
Environment, Natural Resources, and Agricultural Division

_____
G. VINSON HELLWIG
Chief, Air Quality Division
Michigan Department of Environmental Quality

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

**REGION 7**
**901 N. 5th STREET**
**KANSAS CITY, KANSAS 66101**

**AIR PERMITTING AND COMPLIANCE BRANCH**

November 9, 2006

Clark Duffy
Kansas Department of Health & Environment
Bureau of Air and Radiation
1000 S.W. Jackson Street, Suite 310
Topeka, KS 66612-1366

Dear Mr. Duffy,

We appreciate the opportunity to review and provide comments on the proposed PSD permit for the Sunflower Holcomb Station Expansion Project. Our comments focus on recommendations to improve the enforceability of permit conditions, highlight concerns about the $SO_2$ BACT limit and offers suggestions for the continuous emission monitoring portions of the permit.

The underlying assumptions used in the $SO_2$ BACT analysis continues to be our most significant concern. This issue, which we describe in detail in Attachment A and was discussed during the Sunflower pre-application meeting, is one which we have commented on in previous coal-fired projects in Region 7. We hope our analysis helps inform applicants and permit review agencies on a more appropriate selection of the baseline sulfur potential for coal from the Powder River Basin. We encourage KDHE to carefully consider our comments and either establish a firm performance requirement for the scrubber or a range of BACT limits corresponding to the fuels that will be combusted in the Holcomb units. We intend to make similar comments on the other coal-fired projects now under consideration and plan to share these comments with the other Region 7 states.

As always, we appreciate KDHE's efforts in carrying out the PSD program. If you have any questions, please contact Jon Knodel at (913) 551-7622 or at knodel.jon@epa.gov.

Sincerely,

JoAnn Heiman, Acting Chief
Air Permitting and Compliance Branch

Attachments:

Attachment A – EPA Region 7 Comments on Sunflower Holcomb Station Expansion Project for New Units H2, H3 and H4

Attachment B – $SO_2$ Baseline Emissions at Region 7 NSPS Subpart D Units

Attachment C – $SO_2$ Emissions at Public Power Plants in Region 7

Attachment D – Sunflower Holcomb Summary of Subpart Da Emission Reports from July '98 through June '06

Attachment E – Burlington Northern “Guide to Coal Mines” Analysis

Attachment F – Excerpts from KCPL-Hawthorn Scrubber Performance Analysis

Attachment G – Excerpt from City Utilities of Springfield “BACT Emission Limitations for PC Boilers Firing Western Subbituminous Coal”

Attachment H – Excerpts from Draft PSD permit for Longleaf Energy Associates, LLC C/o LS Power Development, LLC

Attachment A
EPA Region 7 Comments on
Sunflower Holcomb Station Expansion Project
for New Units H2, H3 and H4

**SO2 BACT and Baseline Assumptions**

The $SO_2$ baseline selected by Sunflower Holcomb to evaluate BACT appears not to be representative of the Powder River Basin (PRB) coals historically used in Region 7, including Holcomb Unit 1, and should be reevaluated consistent with the comments below.

The department proposes a $SO_2$ BACT limit of 0.095 #/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 1.23 #/mmBtu in conjunction with a 92 percent removal using a dry spray dry adsorber (SDA).

The BACT limit would apply at all times, except during periods of startup, shutdown, and malfunction. In the absence of a percent removal requirement the BACT limit would presumably allow for lesser scrubber performance if lower sulfur fuels are burned. While conceivable that Sunflower Holcomb might have occasion to use a higher sulfur coal, during periods when the lower sulfur coal is unavailable or otherwise uneconomical, or when they blend with bituminous fuels as a mercury reduction strategy, the long term use of such a baseline fuel appears to be unlikely based on historical trends observed over the last 26 years for uncontrolled NSPS utility boilers in Region 7.

To help determine what an appropriate baseline for PRB coal might be, we looked at CEMS data for all uncontrolled NSPS Subpart D utility boilers from 1980 through 2005. The data indicate that $SO_2$ inlet concentrations range from 0.62 to 0.87 #$SO_2$/mmBtu, annual average, respectively. 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 0.73 - 0.87 #$SO_2$/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 of 0.62 - 0.71 #$SO_2$/mmBtu, again with a lowering trend. Despite the requirement to comply with the 1.2 #$SO_2$/mmBtu standard under NSPS Subpart D and to hold sufficient allowances under the title IV Acid Rain Program, it appears these units continue to make fuel choices, based on other incentives that result in $SO_2$ emissions well below their compliance obligations. This indicates that such coals are readily available and have been for many years. Please see Attachment B for more details.

Between 1995 and 2005, 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 in 2002. Nearman Creek is appropriate for comparison to the Sunflower Holcomb Power Station since both are public power facilities and both likely face similar constraints when purchasing compliance coal (e.g. low bid contracts, small purchaser). All annual average emissions data evaluated since 1995 were at or below 0.81 #$SO_2$/mmBtu. Likewise, all emissions data analyzed for uncontrolled NSPS Subpart D utility boilers since 1990, including over 217 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 appears that the baseline used in the Sunflower Holcomb $SO_2$ BACT demonstration may not be representative of pre-control emissions expected while combusting PRB coal.

But, annual average $SO_2$ inlet concentrations may not tell the whole story. Sulfur in coal is variable and can impact short term emission averages. Over longer averaging periods the effects of variability are minimized. Since BACT emission limitations generally must be established using shorter term averages, adjustments to the annual average data may be appropriate. To estimate the magnitude of an annual-to-30-day-rolling-average adjustment, we looked at the monthly variability for the Nearman plant and seven other public power facilities in Region 7 from 1997 through 2002. During this period, monthly emissions – which are similar to those that might be observed using a 30-day rolling average – showed 97% of the $SO_2$ concentrations were less than 0.82 #$SO_2$/mmBtu and 99% were less than 0.90 #$SO_2$/mmBtu. Two of the 846 utility-months of data analyzed had $SO_2$ inlet concentrations greater than 1.0 #$SO_2$/mmBtu and were clearly outliers. See Attachment C for a summary of the analysis.

While clear that utilities included in the Region 7 analysis have periodically used higher sulfur fuels during times when their preferred fuel supply was unavailable, these infrequent events should not serve as the basis for setting a long term BACT standard. 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 used in the Sunflower Holcomb $SO_2$ 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 1.23 #$SO_2$/mmBtu value presented by Sunflower represents a short-term, peak (e.g. instantaneous or1-hr) inlet concentration and the 92% spray dry adsorber (SDA) removal efficiency represents performance over an extended period such as a year, then this apples-to-oranges comparison does not provide a meaningful result. Scrubber performance is usually based on long term performance guarantees and can have higher performance results over the short term. When considered together on a consistent time basis, long term scrubber performance and inlet SO2 potentials appear to result in a substantially lower $SO_2$ BACT limit than proposed in the PSD permit.

In Footnote 3 of “Supplement 3 – Summary of Permit Activity Since Completion of BACT”, Sunflower notes the Holcomb Expansion Project, including new Units H2, H3, and H4, has been planned to make maximum use of existing on-site fuel and reagent supplies and handling equipment and will utilize the same supplies of approximately 0.5 percent western low sulfur coal. While past performance doesn’t necessarily indicate future performance, it is instructive to look at look at historical emission trends when determining if the assumptions used in the BACT analysis are reasonable. To better understand performance at Holcomb Unit H1 over the past several years, we used Sunflower's quarterly NSPS Subpart Da emission reports to

compile a summary of daily, 30-day compliance averages, for Sunflower H1 from July, 1998 to the present. These analyses offer insights on trends of inlet and outlet $SO_2$ concentrations, the effectiveness of the dry scrubber and outlet $NO_x$ and CO emissions.

In general, pre-control inlet $SO_2$ concentrations at Holcomb are consistent with those observed at other Region 7 utilities using PRB coal. Inlet $SO_2$ concentrations, based on 2,620 daily observations made by certified CEMS, range from 0.50 to 0.95 with over 99% of the data below 0.91 #$SO_2$/mmBtu. These data suggest that the design baseline for Holcomb Units H2, H3 and H4 may be too high and should be re-evaluated in light of these actual on site data. Further, the Holcomb data indicates that had it complied with a 92% level of scrubber control – a hypothetical value based on the BACT level of control for the new units – it would have been able to meet a BACT limit of 0.075 #$SO_2$/mmBtu over 100 percent of its operating time. For more information, see excerpts from the spreadsheet titled "Sunflower Subpart Da Emissions Data.xls" in Attachment D and on the enclosed CD.

A report prepared by Burlington Northern and Santa Fe Railway, titled a "Guide to Coal Mines"[ http://www.bnsf.com/markets/coal/pdf/mineguide.pdf ], offers additional insights into coal quality in the region. The report contains general information on the coal mines it serves, many of which are located in the Powder River Basin regions of Wyoming and Montana. We extracted pertinent data for each of the mines and prepared a summary report which is included in Attachment E. The summary shows the $SO_2$ equivalent of PRB-Wyoming to be 0.74 - 0.76 lb$SO_2$/mmBtu, on average. These BNSF data suggest that at a 92% control efficiency or better, the corresponding emissions would be in the range of 0.06 #$SO_2$/mmBtu on a 30 day rolling average.

Setting $SO_2$ BACT at 0.095#$SO_2$/mmBtu, without a corresponding percent reduction requirement, effectively allows Sunflower to operate the SDA at an efficiencies of 83.8% and 90.3% when burning PRB coals with an average $SO_2$ inlet concentration of 0.59 #$SO_2$/mmBtu and 0.98 #$SO_2$/mmBtu, respectively. These $SO_2$ inlet concentrations represent the average and worst case monthly average inlet concentrations for all NSPS Subpart D affected public power units in Region 7 between 1997 and 2005. If realized in practice, this level of scrubber performance falls well short of the long-term design performance anticipated for a SDA as BACT. We have observed this trend first hand at the Kansas City Power and Light Hawthorn Unit 5, where the BACT emission limitation was based on a "worst-case" PRB design baseline that has yet to be utilized. Since 2003, Hawthorn has achieved sustained removal efficiencies of 77 - 82%. Because the permit provides no incentive to reduce further, Hawthorn appears to be operating the scrubber well below its design capability even though it is meeting its BACT limit. Portions of this analysis can be found in Attachment F.

The Sunflower application and permit record could benefit from further evaluation of "better than 92 percent" BACT strategies for $SO_2$. The application and permit record make only brief mention of more rigorous removal options but provide no meaningful discussion on why these strategies were eliminated. However, recent permitting actions for Newmont, LS Power Longleaf, and even the City Utilities of Springfield Southwest projects evaluated, and in some

cases established, "effective" removal efficiencies higher than 92 percent. All concluded that 92 percent, or better, removal is technically and economically feasible with adequate margin of compliance safety. City Utilities of Springfield, for example, prepared a detailed analysis titled "BACT Emission Limitations for PC Boilers Firing Western Subbituminous Coal" [see Attachment G] in support of the PSD permit for its Southwest Power Station. Even though the analysis suffered from the same flaw on PRB baseline coal concentration described above, the study concluded that downtime to complete routine scrubber maintenance, swap out atomizers, and maintain a continuous 94 percent control efficiency would impact its ability to maintain an adequate compliance safety margin. For these reasons, the study concluded that 92 percent control represented BACT. More recent permitting actions at Newmont and LS Power Longleaf conclude that scrubber performance in the 93.5 to 95 percent range should be attainable.

To determine if existing data for the Holcomb and Hawthorn units might help inform the record, we looked at scrubber performance for both units. In general, we concluded that while interesting, the data are not that instructive in setting BACT for the new Holcomb units. The existing Holcomb unit is subject only to a 70% control requirement under NSPS Subpart Da and therefore has had little incentive to control beyond. In 2001 to the present, about the time Sunflower sought approval of its original Sand Sage project, it appears Holcomb began experimenting with the scrubber to achieve higher efficiencies. As a result, the unit experienced even lower $SO_2$ emissions for the past couple of years. Likewise, as indicated above, KCPL Hawthorn has experimented with its scrubber to achieve high rates of removal over short periods of time, but because neither unit has adequate incentives, the scrubber data, in general, do not appear to reflect the effectiveness we would anticipate from a modern dry scrubber design. Therefore, these data do not help to inform the BACT record significantly. We encourage Sunflower to undertake an analysis similar to those for Newmont, LS Power Longleaf, and City Utilities of Springfield, using the proper baseline coal, to document if higher scrubber efficiencies can be maintained, and if not why not.

To compensate for potential under performance of the SDA while burning lower sulfur PRB coals, we believe the final permit should condition Sunflower Holcomb to achieve a 92% reduction, or better, 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 require Sunflower Holcomb to install, operate, maintain, and quality assure an <u>inlet</u> $SO_2$ 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.

In the alternative, if the department decides not to establish an on-going SDA performance requirement as part of the permit, then we believe it is essential that the department establish a series of BACT emission limitations for each coal, or blends, with unique $SO_2$ inlet concentration characteristics. For example, if Sunflower Holcomb anticipates they may utilize a PRB coal, or bituminous blend, with a 1.23 #$SO_2$/mmBtu inlet concentration, then a BACT limit of 0.095 may be appropriate during those limited periods of time. On the other hand, if Sunflower Holcomb combusts PRB with sulfur characteristics more typical of those burned by

Holcomb and similar utilities throughout the region, then a $SO_2$ emission limitation of 0.060 – 0.075 #$SO_2$/mmBtu appears to be a more appropriate BACT limit. A good example of this tiered approach was proposed by LS Power Longleaf. This project is currently undergoing public comment at the Georgia Department of Natural Resources and the relevant excerpts can be found in Attachment H. This permit is particularly interesting because many of the key design features, including the type of fuel and control technologies, are similar to those proposed by Sunflower. In brief, the Georgia permit establishes three $SO_2$ BACT limits, premised on a 93.5% removal efficiency, that vary depending on the $SO_2$ inlet concentration to the boiler. The proposed permit limits, while derived in a different manner than we describe above, are consistent with those we recommend above.

In summary, we believe it is inappropriate to establish BACT on a set of factors that occurs less than one percent of the time and thus undermines a BACT level of control during the remaining 99 percent of normal operations. Based on the Sunflower permit record and our review of other similar projects in the Region, the 0.095 # $SO_2$/mmBtu BACT limit, by itself, does not effectively implement a BACT level of control over the variability of fuel inputs Sunflower may choose to use. Therefore, we recommend that the department establish an explicit $SO_2$ percent removal requirement, no less than 92%, or in the alternative two or more BACT limits that reflect at least 92% control over a range of $SO_2$ inlet concentrations. We want to make clear that it is not our intent to limit Sunflower's fuel flexibility to use a range of low sulfur PRB coals or other modest low sulfur bituminous blends, but rather to assure that a BACT level of control is achieved at all times.

As a general disclaimer, we clearly understand that the proposed Sunflower Holcomb units are not uncontrolled utility boilers subject to NSPS Subpart D. Nevertheless, the data analyzed for Holcomb and other units in the Region are highly informative on $SO_2$ inlet potential concentration for units combusting PRB coal and should not be overlooked. To assist the department in its investigation of the baseline coal issue, the enclosed CD-ROM contains the spreadsheets with all of the analysis described above.

**Continuous Particulate Matter Monitoring (PM-CEMS)**

In 2004, EPA promulgated final performance specifications, PS-11, for installation, operation, maintenance, and quality assurance of continuous particulate matter emission monitoring systems (PM-CEMS). For a number of reasons, we believe the proposed Sunflower Holcomb units are capable of installing this equipment and pushing the knowledge base forward. First, these are state-of-the-art utility boilers 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 PC-CEMS is a valuable tool to help enhance baghouse performance while also providing direct information to verify that the unit is meeting its PM BACT emission limitation. Third, utility companies typically have very experienced

instrumentation staff. Sunflower is no exception, having nearly 30 years of experience operating a Subpart Da CEMS network and another 10 years running the sophisticated acid rain monitoring equipment. Sunflower clearly 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. Fourth, utility companies typically have the economic resources to purchase complicated monitoring technologies and the support necessary to ultimately make them work. Fifth, Sunflower has demonstrated leadership in the past on a number of technical initiatives with the Electric Power Research Institute and the Department of Energy. We'd like to encourage this same level of exploration to move the PM-CEMS technology forward. Sixth, these devices have been required as part of the national power plant enforcement cases and most of the recently issued PSD permits. We want to see this trend continue and encourage all of the Region 7 states to promote PM-CEMS for large coal-fired utility projects. Lastly, the coarse filterable PM limit in "Air Emission Limitations" 2c. lends itself to measurement using a PM-CEMS. When these factors are considered together, it seems appropriate to promote the technology and look for "beyond the NSPS" solutions. In that regard, we strongly encourage the department to work with Sunflower to incorporate PM-CEMs for the new Holcomb units.

**CO BACT and Continuous Emission Monitoring**

As part of our analysis of Sunflower quarterly Subpart Da emission reports, we looked at CO emissions reported for Holcomb Unit H1. Sunflower reports these emissions pursuant to its federal PSD permit. In general, the data indicate that CO emissions are very low, in the range of 0.02 to 0.05 #CO/mmBtu, 30 day rolling average. While not directly comparable to CO emissions from the new units, because of the low $NO_x$ burner technology and selective catalytic reduction units proposed for the new boilers, it would be instructive to have similar monitoring information to assure compliance with the higher 0.15 #/mmBtu, short term average BACT limit. We recommend that KDHE replace the one time initial stack test under "Compliance and Other Performance Testing" Condition 1 with a requirement for Sunflower to install, calibrate, maintain, and quality assure CO-CEMS on each of the three new units. These continuous data provide valuable information which allows Sunflower to certify annual compliance under its Title V permit. CO data can often also assist the boiler operator to optimize combustion and maximize fuel efficiency. As part of this reconsideration, KDHE should determine whether it would be more appropriate to retain the short term averaging period and current proposed BACT limit or lengthen the averaging period (e.g. 30 day rolling) and lower the BACT limit since any variability in short term transient spikes would be flattened over time.

**CEMS... In General**

The permit requires installation of $NO_x$ and $SO_2$ CEMS consistent with NSPS Subpart Da, but is silent on the use of the CEMS data for verification of BACT limits in the permit. We'd like to see an explicit statement in the permit that Sunflower will install, operate, maintain, and quality assure such CEMS to verify direct compliance with the BACT limits. This approach helps meet the compliance assurance monitoring (CAM) requirements under Title V, allows Sunflower to certify annual compliance with the permit limits, provides the public with direct compliance information and minimizes any confusion over the use of CEMS data at some later date. There is no doubt that the CEMS data constitute direct compliance data under NSPS Subpart Da, so it shouldn't be controversial to extend this clarification to the PSD permit as well.

**Boiler Operating Day**

The draft permit, under "Air Emission Limitations" Condition 2, 2nd paragraph, notes that "day" [as in boiler operating day] shall have the same meaning as in NSPS Subpart Da. For units constructed prior to February 28, 2005, a boiler operating day is one in which the boiler operates the entire 24-hour period. For new units constructed after that date, a boiler operating day is one on which the boiler operates for any period of time. Given the contentious nature of the Subpart Da revisions and uncertainty in how these issues might be resolved, we believe it is appropriate for the PSD permit to consider all periods of normal operation in the calculation of the 30-day rolling average, whether the boiler operates all 24 hours in a day or not. This approach assures that valid CEMS data are not arbitrarily discarded when determining compliance with the BACT limits just because the boiler does not operate the entire 24-hour period. Hard coding the definition of "boiler operating day" in the permit also provides assurance to Sunflower, KDHE, EPA, and the public that the compliance procedures for the PSD permit remain static, independent from Subpart Da, and minimize the impacts of having to make expensive software changes to the data acquisition and handling system.

**$PM_{10}$ BACT Limit and Process for Change of Limit**

"Compliance and Other Performance Testing" Condition 8 describes a process that allows Sunflower to petition KDHE for a new $PM_{10}$ limit if unable to achieve the 0.018 #/mmBtu BACT limitation after the initial compliance demonstration and subsequent evaluation period. While we don't object in principle to the general approach outlined in the permit -- as long as Sunflower makes bone fide efforts to meet the 0.018 #/mmBtu BACT limit -- we have concerns about the unilateral approach KDHE gives itself to adopt the new limit. Given the diverse opinion on $PM_{10}$ test methods and how such test data may be used, we believe that any change in the $PM_{10}$ limit should undergo an opportunity for public and EPA peer review. Therefore, we ask KDHE to revise Condition 8, or other as appropriate, to include an explicit requirement for public review of the departments action. We also recommend that Sunflower and KDHE coordinate development of the testing protocol with EPA Region 7 to assure that there are "no surprises" before or after the testing program commences.

**BACT and Modeling Analysis for Units that Commence Construction beyond the Initial 18 Month Period**

"General Provisions", Condition 2, requires Sunflower to submit information for reevaluation of the BACT and modeling analyses for any unit that does not commence construction within the initial 18 months of permit issuance. It is important that KDHE retain this requirement to assure that each unit, before constructed, has been reviewed for the latest developments in air pollution control technology and that subsequent emissions growth in the area have not exceeded the NAAQS or PSD increments. Where multiple units are involved, there can sometimes be confusion about the severability of this requirement, so it is imperative to make clear that unless all three units commence construction, as defined in the PSD rules, within the initial 18 month period those units that do not must undergo reanalysis. KDHE's proposed permit language appears to carry out this concept, but could benefit from additional clarity as described below.

Once Sunflower submits a reanalysis of BACT and modeling studies, KDHE may authorize an additional 18 months in which Sunflower may commence construction of subsequent units. As we note in our comments on revision of the $PM_{10}$ BACT limit, any such permit extension for subsequent units should benefit from public and EPA peer review. Therefore, we recommend that KDHE add this additional clarification.

Lastly, if Sunflower does not commence construction on one or more of the units and does not provide the analysis required by the permit in a time frame prior to the close of the 18 month period, KDHE should make clear that authorization to construct any subsequent units automatically becomes void. It is essential that Sunflower submit the reanalysis in a timely fashion or they must begin a new PSD permitting review. Again, KDHE may want to provide this clarification in the permit, or associated record, so there is no confusion later on.

**Short Term $SO_2$ Limit Based on Modeling Analysis**

The revised AERMOD modeling analysis, submitted in September, 2006, notes that it may be appropriate to establish a short term 3-hour limit for $SO_2$. This limit would assure the modeling assumptions remain valid if Sunflower chooses to combust coal with sulfur content greater than 0.5%. Since the permit does not restrict fuel flexibility, we recommend that the department include the recommended limit, 4,358 #/hr, 3-hour average, as a condition of the permit.

[End of Comments]

**Attachment B**
**$SO_2$ Baseline Emissions at**
**Region 7 NSPS Subpart D Units**

# SO2 Emissions Data for NSPS Subpart D (unscrubbed) Units

| | | 1980 | 1985 | 1990 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 1980 – 2005 Average | 1980-2005 (Max) | 1980-2005 (min) | Maximum Swing from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SO2 Rate | Ames 8 | | 1.12 | 0.41 | 0.40 | 0.42 | 0.44 | 0.36 | 0.36 | 0.38 | 0.34 | 0.36 | 0.34 | 0.34 | 0.34 | 0.40 | 1.12 | 0.34 | 0.72 |
| | CBEC 3 | 0.68 | 0.85 | 0.66 | 0.76 | 0.70 | 0.73 | 0.80 | 0.74 | 0.68 | 0.65 | 0.65 | 0.59 | 0.52 | 0.55 | 0.68 | 0.85 | 0.52 | 0.17 |
| | Neal 3 | 1.13 | 1.32 | 0.73 | 0.83 | 0.73 | 0.73 | 0.72 | 0.68 | 0.66 | 0.72 | 0.67 | 0.70 | 0.71 | 0.68 | 0.76 | 1.32 | 0.66 | 0.56 |
| | Neal 4 | 1.13 | 0.73 | 0.72 | 0.71 | 0.77 | 0.76 | 0.77 | 0.73 | 0.65 | 0.71 | 0.68 | 0.74 | 0.63 | 0.67 | 0.74 | 1.13 | 0.63 | 0.39 |
| | Lansing 4 | 1.16 | 0.70 | 0.67 | 0.69 | 0.61 | 0.58 | 0.77 | 0.74 | 0.66 | 0.63 | 0.55 | 0.61 | 0.65 | 0.65 | 0.69 | 1.16 | 0.55 | 0.47 |
| | Louisa 101 | | 0.79 | 0.75 | 0.76 | 0.77 | 0.75 | 0.72 | 0.70 | 0.64 | 0.59 | 0.58 | 0.58 | 0.65 | 0.60 | 0.67 | 0.79 | 0.58 | 0.12 |
| | Ottumwa 1 | | 0.82 | 0.72 | 0.71 | 0.77 | 0.71 | 0.72 | 0.70 | 0.66 | 0.65 | 0.59 | 0.67 | 0.66 | 0.64 | 0.69 | 0.82 | 0.59 | 0.13 |
| | LaCygne 2 | 4.14 | 0.94 | 0.83 | 0.70 | 0.77 | 0.75 | 0.78 | 0.73 | 0.68 | 0.72 | 0.69 | 0.69 | 0.69 | 0.74 | 0.73 | 4.14 | 0.68 | 3.40 |
| | Nearman 1 | | 0.82 | 0.75 | 0.72 | 0.67 | 0.67 | 0.76 | 0.84 | 0.72 | 0.78 | 0.81 | 0.77 | 0.78 | 0.77 | 0.76 | 0.84 | 0.67 | 0.09 |
| | Iatan 1 | 0.66 | 0.77 | 0.72 | 0.72 | 0.72 | 0.75 | 0.76 | 0.74 | 0.65 | 0.62 | 0.61 | 0.65 | 0.70 | 0.73 | 0.70 | 0.77 | 0.61 | 0.09 |
| | GG 1 | 0.73 | 0.72 | 0.73 | 0.62 | 0.63 | 0.47 | 0.47 | 0.47 | 0.52 | 0.57 | 0.59 | 0.56 | 0.60 | 0.49 | 0.57 | 0.73 | 0.47 | 0.17 |
| | GG 2 | | 0.73 | 0.72 | 0.61 | 0.62 | 0.48 | 0.51 | 0.47 | 0.50 | 0.57 | 0.57 | 0.54 | 0.58 | 0.53 | 0.56 | 0.73 | 0.47 | 0.16 |
| | Whelan 1 | | 0.91 | 0.50 | 0.52 | 0.68 | 0.63 | 0.64 | 0.72 | 0.64 | 0.61 | 0.67 | 0.66 | 0.69 | 0.74 | 0.66 | 0.91 | 0.50 | 0.26 |
| | Lon Wright | 0.72 | 0.88 | 0.86 | 0.92 | 0.61 | 0.56 | 0.58 | 0.46 | 0.48 | 0.49 | 0.44 | 0.45 | 0.47 | 0.47 | 0.56 | 0.92 | 0.44 | 0.36 |
| | NE City 1 | 0.80 | 0.92 | 0.70 | 0.79 | 0.72 | 0.76 | 0.53 | 0.71 | 0.67 | 0.68 | 0.63 | 0.62 | 0.70 | 0.73 | 0.70 | 0.92 | 0.53 | 0.22 |
| | Platte 1 | | 0.98 | 0.75 | 0.66 | 0.65 | 0.64 | 0.84 | 0.72 | 0.66 | 0.60 | 0.62 | 0.53 | 0.53 | 0.59 | 0.65 | 0.98 | 0.53 | 0.32 |
| Weighted Average | | 0.87 | 0.83 | 0.73 | 0.71 | 0.71 | 0.67 | 0.68 | 0.67 | 0.64 | 0.64 | 0.62 | 0.63 | 0.64 | 0.63 | 0.68 | 4.14 | 0.34 | 3.40 |

| | | 1980 | 1985 | 1990 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | Sum |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SO2 Tons | Ames 8 | 0 | 1,220 | 596 | 387 | 693 | 770 | 696 | 772 | 656 | 786 | 829 | 731 | 792 | 784 | 9,710 |
| | CBEC 3 | 11,409 | 14,782 | 12,780 | 18,476 | 17,914 | 17,279 | 22,662 | 18,515 | 17,718 | 18,001 | 17,143 | 16,107 | 12,653 | 15,294 | 230,733 |
| | Neal 3 | 13,955 | 8,879 | 10,284 | 14,894 | 10,327 | 11,563 | 14,504 | 12,419 | 11,071 | 13,073 | 10,076 | 12,818 | 11,459 | 14,084 | 169,405 |
| | Neal 4 | 20,153 | 14,660 | 16,325 | 18,527 | 19,025 | 18,675 | 16,223 | 17,638 | 14,973 | 16,105 | 15,617 | 14,907 | 14,950 | 14,165 | 231,942 |
| | Lansing 4 | 7,666 | 4,011 | 4,092 | 3,109 | 3,208 | 2,920 | 4,979 | 6,882 | 5,701 | 4,489 | 3,604 | 3,917 | 4,633 | 5,060 | 64,270 |
| | Louisa 101 | 0 | 7,718 | 11,388 | 13,213 | 17,274 | 16,166 | 17,640 | 16,466 | 14,779 | 14,304 | 15,901 | 13,974 | 16,725 | 12,326 | 187,874 |
| | Ottumwa 1 | 0 | 12,192 | 13,110 | 18,601 | 17,773 | 16,277 | 20,198 | 18,392 | 18,415 | 17,276 | 15,980 | 18,464 | 16,093 | 11,977 | 214,748 |
| | LaCygne 2 | | 12,979 | 18,868 | 22,284 | 21,266 | 11,303 | 18,915 | 19,013 | 20,983 | 20,309 | 19,355 | 20,606 | 20,694 | 20,974 | 247,549 |
| | Nearman 1 | 0 | 6,290 | 5,663 | 6,501 | 5,841 | 6,620 | 7,739 | 6,355 | 7,596 | 8,388 | 7,625 | 8,727 | 8,024 | 7,242 | 92,611 |
| | Iatan 1 | 11,886 | 16,174 | 15,394 | 19,289 | 18,713 | 17,927 | 19,296 | 17,397 | 13,430 | 16,283 | 14,856 | 18,400 | 19,219 | 19,217 | 237,482 |
| | GG 1 | 9,326 | 8,176 | 9,354 | 14,545 | 13,492 | 11,643 | 11,167 | 10,698 | 9,604 | 16,694 | 15,681 | 16,613 | 15,453 | 14,001 | 176,446 |
| | GG 2 | 0 | 12,135 | 11,677 | 13,417 | 12,534 | 11,237 | 11,917 | 10,806 | 12,988 | 14,603 | 16,471 | 14,476 | 16,582 | 14,170 | 173,014 |
| | Whelan 1 | 0 | 1,052 | 656 | 1,558 | 2,072 | 1,700 | 1,894 | 2,251 | 2,164 | 2,008 | 2,007 | 2,152 | 2,352 | 2,563 | 24,429 |
| | Lon Wright | 989 | 1,244 | 1,244 | 969 | 914 | 1,086 | 928 | 987 | 841 | 1,088 | 978 | 1,017 | 1,181 | 1,332 | 14,798 |
| | NE City 1 | 8,757 | 11,444 | 11,230 | 17,138 | 13,469 | 12,233 | 12,832 | 17,697 | 15,227 | 16,206 | 12,820 | 15,052 | 15,593 | 17,550 | 197,247 |
| | Platte 1 | 0 | 1,521 | 1,779 | 1,729 | 2,213 | 2,004 | 2,782 | 2,564 | 2,497 | 2,436 | 2,250 | 2,194 | 2,158 | 2,476 | 28,603 |
| Sum | | 84,141 | 134,477 | 144,440 | 184,637 | 176,727 | 159,403 | 184,372 | 178,852 | 168,642 | 182,049 | 171,192 | 180,154 | 178,560 | 173,216 | 2,300,862 |

| | | 1980 | 1985 | 1990 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | Sum |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Heat Input | Ames 8 | 0 | 2,174,451 | 2,920,755 | 1,928,456 | 3,275,676 | 3,539,724 | 3,848,677 | 4,257,355 | 3,465,327 | 4,559,244 | 4,668,367 | 4,325,846 | 4,614,100 | 4,647,573 | 48,225,551 |
| | CBEC 3 | 33,415,067 | 34,693,600 | 38,779,014 | 48,493,286 | 51,489,851 | 47,263,735 | 56,398,862 | 49,979,382 | 51,996,320 | 55,491,695 | 52,962,126 | 54,710,494 | 48,280,512 | 55,832,515 | 679,786,459 |
| | Neal 3 | 24,760,176 | 13,465,981 | 28,297,622 | 35,708,260 | 28,253,590 | 31,773,385 | 40,046,979 | 36,609,523 | 33,331,686 | 36,366,602 | 29,860,020 | 36,374,200 | 32,098,443 | 41,315,851 | 448,262,318 |
| | Neal 4 | 35,723,677 | 40,433,288 | 45,253,308 | 51,906,380 | 49,134,775 | 48,865,106 | 41,961,014 | 48,430,272 | 45,750,910 | 45,264,970 | 46,184,489 | 40,179,828 | 47,244,408 | 42,093,247 | 628,425,672 |
| | Lansing 4 | 13,178,260 | 11,541,000 | 12,211,136 | 8,998,610 | 10,484,851 | 10,076,882 | 12,897,358 | 18,549,631 | 17,341,366 | 14,322,847 | 13,051,449 | 12,932,001 | 14,266,400 | 15,486,117 | 185,337,908 |
| | Louisa 101 | 0 | 19,428,025 | 30,517,044 | 34,927,846 | 44,649,934 | 42,876,657 | 48,700,212 | 46,994,351 | 46,476,768 | 48,801,338 | 54,925,058 | 48,112,993 | 51,819,846 | 40,937,045 | 559,167,117 |
| | Ottumwa 1 | 0 | 29,825,416 | 36,555,218 | 52,070,139 | 46,445,832 | 45,603,035 | 56,279,697 | 52,697,255 | 55,464,741 | 52,855,750 | 54,110,578 | 54,763,895 | 48,522,589 | 37,574,676 | 622,768,821 |
| | LaCygne 2 | | 27,512,272 | 45,230,987 | 63,957,738 | 55,415,961 | 30,279,155 | 48,739,770 | 52,383,662 | 61,530,633 | 56,376,554 | 55,983,769 | 59,874,983 | 59,766,097 | 57,052,244 | 674,103,825 |
| | Nearman 1 | 0 | 15,360,366 | 15,170,225 | 18,144,298 | 17,535,364 | 19,715,621 | 20,249,849 | 15,052,235 | 20,970,307 | 21,537,256 | 18,782,214 | 22,531,661 | 20,506,619 | 18,870,938 | 244,426,953 |
| | Iatan 1 | 35,899,829 | 42,130,380 | 42,744,348 | 53,922,368 | 51,830,862 | 47,679,197 | 50,507,808 | 46,905,347 | 41,421,377 | 52,388,339 | 48,359,038 | 57,016,403 | 55,081,257 | 52,746,059 | 678,632,612 |
| | GG 1 | 25,461,324 | 22,784,110 | 25,653,820 | 46,803,429 | 43,068,200 | 50,070,589 | 47,766,100 | 45,641,344 | 36,910,068 | 58,836,292 | 53,311,364 | 59,639,515 | 51,456,566 | 56,736,780 | 624,139,501 |
| | GG 2 | 0 | 33,454,441 | 32,393,500 | 44,180,936 | 40,499,998 | 47,170,836 | 46,826,700 | 46,312,978 | 52,392,994 | 50,999,608 | 57,940,211 | 53,919,191 | 56,828,555 | 53,378,729 | 616,298,677 |
| | Whelan 1 | 0 | 2,304,761 | 2,616,556 | 5,985,310 | 6,097,107 | 5,393,551 | 5,956,163 | 6,227,080 | 6,766,352 | 6,621,829 | 6,024,409 | 6,562,721 | 6,827,668 | 6,911,747 | 74,295,254 |
| | Lon Wright | 2,743,950 | 2,820,150 | 2,884,299 | 2,101,794 | 2,998,353 | 3,891,921 | 3,224,196 | 4,292,952 | 3,514,086 | 4,480,941 | 4,475,420 | 4,499,446 | 5,061,937 | 5,626,441 | 52,615,886 |
| | NE City 1 | 21,840,893 | 24,868,328 | 32,252,616 | 43,336,246 | 37,192,515 | 32,265,486 | 48,373,096 | 49,520,464 | 45,168,470 | 47,859,791 | 40,902,362 | 48,405,745 | 44,426,103 | 48,402,870 | 564,814,985 |
| | Platte 1 | 0 | 3,120,000 | 4,748,344 | 5,249,669 | 6,791,756 | 6,218,873 | 6,609,078 | 7,124,489 | 7,612,963 | 8,118,457 | 7,255,057 | 8,234,073 | 8,181,207 | 8,397,149 | 87,661,115 |
| Sum | | 193,023,176 | 325,916,569 | 398,228,792 | 517,714,765 | 495,164,625 | 472,683,753 | 538,385,559 | 530,978,320 | 530,114,368 | 564,881,513 | 548,795,931 | 572,082,995 | 554,982,307 | 546,009,981 | 6,788,962,654 |

**Attachment C**
**$SO_2$ Emissions at Public Power Plants in Region 7**

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IA | Ames | 1122 | 8 | 1997 | 1 | 87 | 0.44 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 2 | 69 | 0.44 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 3 | 28 | 0.39 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 4 | 68 | 0.51 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 5 | 96 | 0.48 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 6 | 71 | 0.46 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 7 | 82 | 0.39 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 8 | 82 | 0.43 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 9 | 71 | 0.41 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 10 | 79 | 0.44 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 11 | 37 | 0.39 | | | | |
| IA | Ames | 1122 | 8 | 1997 | 12 | | - | 0.44 | 0.51 | 0.39 | 0.07 |
| IA | Ames | 1122 | 8 | 1998 | 1 | 7 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 2 | 45 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 3 | 75 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 4 | 39 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 5 | 45 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 6 | 74 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 7 | 83 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 8 | 77 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 9 | 53 | 0.40 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 10 | 66 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 11 | 61 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1998 | 12 | 71 | 0.35 | 0.36 | 0.40 | 0.33 | 0.04 |
| IA | Ames | 1122 | 8 | 1999 | 1 | 58 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 2 | 64 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 3 | 53 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 4 | 81 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 5 | 18 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 6 | 77 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 7 | 86 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 8 | 83 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 9 | 69 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 10 | 51 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 11 | 47 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 1999 | 12 | 86 | 0.38 | 0.36 | 0.38 | 0.35 | 0.02 |
| IA | Ames | 1122 | 8 | 2000 | 1 | 99 | 0.42 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 2 | 88 | 0.39 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 3 | 93 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 4 | 20 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 5 | | - | | | | |
| IA | Ames | 1122 | 8 | 2000 | 6 | 46 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 7 | 81 | 0.41 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 8 | 79 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 9 | 76 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 10 | 68 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2000 | 11 | | - | | | | |
| IA | Ames | 1122 | 8 | 2000 | 12 | 7 | 0.32 | 0.38 | 0.42 | 0.32 | 0.06 |
| IA | Ames | 1122 | 8 | 2001 | 1 | 76 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 2 | 76 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 3 | 93 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 4 | 77 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 5 | 78 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 6 | 47 | 0.32 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 7 | 66 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 8 | 66 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 9 | 68 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 10 | 72 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 11 | 43 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2001 | 12 | 26 | 0.33 | 0.34 | 0.36 | 0.32 | 0.02 |
| IA | Ames | 1122 | 8 | 2002 | 1 | 72 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 2 | 63 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 3 | 64 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 4 | 75 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 5 | 61 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 6 | 76 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 7 | 74 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 8 | 74 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 9 | 71 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 10 | 65 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 11 | 62 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2002 | 12 | 71 | 0.34 | 0.36 | 0.38 | 0.34 | 0.02 |
| IA | Ames | 1122 | 8 | 2003 | 1 | 78 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 2 | 76 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 3 | 51 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 4 | 2 | 0.32 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 5 | 66 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 6 | 65 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 7 | 68 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 8 | 70 | 0.30 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 9 | 70 | 0.31 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IA | Ames | 1122 | 8 | 2003 | 10 | 64 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 11 | 39 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2003 | 12 | 82 | 0.36 | 0.34 | 0.36 | 0.30 | 0.04 |
| IA | Ames | 1122 | 8 | 2004 | 1 | 76 | 0.30 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 2 | 61 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 3 | 97 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 4 | 5 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 5 | 65 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 6 | 70 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 7 | 83 | 0.37 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 8 | 72 | 0.32 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 9 | 77 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 10 | 62 | 0.39 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 11 | 49 | 0.30 | | | | |
| IA | Ames | 1122 | 8 | 2004 | 12 | 74 | 0.33 | 0.34 | 0.39 | 0.30 | 0.05 |
| IA | Ames | 1122 | 8 | 2005 | 1 | 82 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 2 | 67 | 0.34 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 3 | 81 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 4 | 2 | 0.32 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 5 | 60 | 0.38 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 6 | 82 | 0.36 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 7 | 83 | 0.35 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 8 | 78 | 0.31 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 9 | 75 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 10 | 65 | 0.32 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 11 | 38 | 0.33 | | | | |
| IA | Ames | 1122 | 8 | 2005 | 12 | 72 | 0.34 | 0.34 | 0.38 | 0.31 | 0.04 |
| KS | Nearman Creek | 6064 | N1 | 1997 | 1 | 517 | 0.65 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 2 | 464 | 0.64 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 3 | 426 | 0.63 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 4 | 605 | 0.68 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 5 | 311 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 6 | 589 | 0.67 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 7 | 587 | 0.63 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 8 | 527 | 0.52 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 9 | 683 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 10 | 664 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 11 | 611 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1997 | 12 | 636 | 0.70 | 0.67 | 0.76 | 0.52 | 0.15 |
| KS | Nearman Creek | 6064 | N1 | 1998 | 1 | 582 | 0.70 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 2 | 639 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 3 | 662 | 0.71 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 4 | 783 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 5 | 313 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 6 | 714 | 0.77 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 7 | 761 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 8 | 480 | 0.72 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 9 | 733 | 0.79 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 10 | 659 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 11 | 723 | 0.77 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1998 | 12 | 689 | 0.75 | 0.76 | 0.82 | 0.70 | 0.06 |
| KS | Nearman Creek | 6064 | N1 | 1999 | 1 | 743 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 2 | 668 | 0.84 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 3 | 633 | 0.84 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 4 | | - | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 5 | 387 | 1.25 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 6 | 648 | 0.88 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 7 | 500 | 0.89 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 8 | 407 | 0.96 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 9 | 335 | 0.80 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 10 | 680 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 11 | 662 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 1999 | 12 | 691 | 0.77 | 0.84 | 1.25 | 0.77 | 0.41 |
| KS | Nearman Creek | 6064 | N1 | 2000 | 1 | 545 | 0.73 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 2 | 393 | 0.66 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 3 | 597 | 0.72 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 4 | 664 | 0.66 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 5 | 351 | 0.68 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 6 | 681 | 0.70 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 7 | 763 | 0.72 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 8 | 806 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 9 | 754 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 10 | 791 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 11 | 739 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2000 | 12 | 511 | 0.70 | 0.72 | 0.78 | 0.66 | 0.06 |
| KS | Nearman Creek | 6064 | N1 | 2001 | 1 | 802 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 2 | 654 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 3 | 804 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 4 | 740 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 5 | 415 | 0.73 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 6 | 689 | 0.74 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| KS | Nearman Creek | 6064 | N1 | 2001 | 7 | 721 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 8 | 708 | 0.79 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 9 | 764 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 10 | 592 | 0.80 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 11 | 715 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2001 | 12 | 783 | 0.84 | 0.78 | 0.84 | 0.73 | 0.06 |
| KS | Nearman Creek | 6064 | N1 | 2002 | 1 | 762 | 0.79 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 2 | 671 | 0.87 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 3 | 704 | 0.80 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 4 | 229 | 0.77 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 5 | 735 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 6 | 708 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 7 | 742 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 8 | 741 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 9 | 702 | 0.80 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 10 | 722 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 11 | 179 | 0.78 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2002 | 12 | 729 | 0.82 | 0.81 | 0.87 | 0.77 | 0.05 |
| KS | Nearman Creek | 6064 | N1 | 2003 | 1 | 705 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 2 | 761 | 0.85 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 3 | 556 | 0.85 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 4 | 567 | 0.71 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 5 | 837 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 6 | 686 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 7 | 832 | 0.77 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 8 | 838 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 9 | 800 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 10 | 576 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 11 | 716 | 0.72 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2003 | 12 | 854 | 0.76 | 0.77 | 0.85 | 0.71 | 0.07 |
| KS | Nearman Creek | 6064 | N1 | 2004 | 1 | 794 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 2 | 786 | 0.83 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 3 | 818 | 0.84 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 4 | 273 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 5 | 760 | 0.79 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 6 | 665 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 7 | 572 | 0.76 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 8 | 577 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 9 | 658 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 10 | 777 | 0.77 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 11 | 658 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2004 | 12 | 686 | 0.72 | 0.78 | 0.84 | 0.72 | 0.07 |
| KS | Nearman Creek | 6064 | N1 | 2005 | 1 | 743 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 2 | 435 | 0.79 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 3 | 563 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 4 | 342 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 5 | 560 | 0.82 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 6 | 841 | 0.81 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 7 | 760 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 8 | 680 | 0.74 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 9 | 688 | 0.80 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 10 | 480 | 0.75 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 11 | 498 | 0.72 | | | | |
| KS | Nearman Creek | 6064 | N1 | 2005 | 12 | 653 | 0.74 | 0.77 | 0.82 | 0.72 | 0.05 |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 1 | 1186 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 2 | 1041 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 3 | 849 | 0.42 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 4 | 1122 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 5 | 922 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 6 | 1022 | 0.48 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 7 | 989 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 8 | 886 | 0.48 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 9 | 979 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 10 | 856 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 11 | 957 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1997 | 12 | 836 | 0.46 | 0.47 | 0.50 | 0.42 | 0.05 |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 1 | 803 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 2 | 974 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 3 | 646 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 4 | 870 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 5 | 861 | 0.43 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 6 | 998 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 7 | 887 | 0.44 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 8 | 1140 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 9 | 885 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 10 | 1168 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 11 | 960 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1998 | 12 | 976 | 0.44 | 0.47 | 0.51 | 0.43 | 0.05 |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 1 | 934 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 2 | 872 | 0.43 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 3 | 135 | 0.36 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 4 | 797 | 0.40 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 5 | 814 | 0.40 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 6 | 930 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 7 | 1190 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 8 | 1088 | 0.48 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 9 | 800 | 0.44 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 10 | 1056 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 11 | 1075 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 1999 | 12 | 1008 | 0.49 | 0.47 | 0.57 | 0.36 | 0.11 |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 1 | 989 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 2 | 965 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 3 | 1130 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 4 | 945 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 5 | 1060 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 6 | 917 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 7 | 852 | 0.42 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 8 | 1030 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 9 | 403 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 10 | | - | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 11 | 0 | 0.02 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2000 | 12 | 1313 | 0.56 | 0.52 | 0.56 | 0.02 | 0.50 |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 1 | 1538 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 2 | 1393 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 3 | 1543 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 4 | 1421 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 5 | 1442 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 6 | 1391 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 7 | 1423 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 8 | 1456 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 9 | 1271 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 10 | 967 | 0.66 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 11 | 1412 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2001 | 12 | 1438 | 0.56 | 0.57 | 0.66 | 0.54 | 0.09 |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 1 | 1526 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 2 | 1414 | 0.62 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 3 | 1531 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 4 | 1495 | 0.61 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 5 | 1398 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 6 | 1408 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 7 | 1486 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 8 | 1359 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 9 | 942 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 10 | 512 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 11 | 1344 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2002 | 12 | 1266 | 0.56 | 0.59 | 0.62 | 0.55 | 0.04 |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 1 | 1491 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 2 | 1207 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 3 | 1453 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 4 | 1368 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 5 | 1496 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 6 | 1357 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 7 | 1375 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 8 | 1330 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 9 | 1422 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 10 | 1337 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 11 | 1300 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2003 | 12 | 1477 | 0.58 | 0.56 | 0.59 | 0.53 | 0.03 |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 1 | 1495 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 2 | 1433 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 3 | 577 | 0.61 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 4 | 550 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 5 | 1488 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 6 | 1378 | 0.64 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 7 | 1534 | 0.64 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 8 | 1519 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 9 | 1323 | 0.61 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 10 | 1237 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 11 | 1414 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2004 | 12 | 1505 | 0.58 | 0.60 | 0.64 | 0.57 | 0.04 |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 1 | 1329 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 2 | 978 | 0.41 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 3 | 862 | 0.33 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 4 | 576 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 5 | 1389 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 6 | 1125 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 7 | 1353 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 8 | 1248 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 9 | 1279 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 10 | 1245 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 11 | 1297 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 1 | 2005 | 12 | 1320 | 0.50 | 0.49 | 0.54 | 0.33 | 0.16 |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 1 | 1044 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 2 | 761 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 3 | 930 | 0.42 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 4 | 974 | 0.44 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 5 | 752 | 0.47 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 6 | 741 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 7 | 1056 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 8 | 909 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 9 | 819 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 10 | 995 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 11 | 1121 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1997 | 12 | 1137 | 0.50 | 0.48 | 0.56 | 0.42 | 0.08 |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 1 | 928 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 2 | 959 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 3 | 946 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 4 | 935 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 5 | 1096 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 6 | 940 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 7 | 1090 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 8 | 1064 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 9 | 590 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 10 | 1069 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 11 | 1129 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1998 | 12 | 1171 | 0.49 | 0.51 | 0.56 | 0.46 | 0.05 |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 1 | 1070 | 0.48 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 2 | 890 | 0.43 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 3 | 1197 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 4 | 65 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 5 | 363 | 0.41 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 6 | 985 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 7 | 1235 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 8 | 1082 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 9 | 797 | 0.44 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 10 | 1019 | 0.45 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 11 | 1017 | 0.46 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 1999 | 12 | 1085 | 0.46 | 0.47 | 0.51 | 0.41 | 0.05 |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 1 | 1231 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 2 | 903 | 0.48 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 3 | 1367 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 4 | 1308 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 5 | 1241 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 6 | 852 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 7 | 1203 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 8 | 1220 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 9 | 945 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 10 | 1198 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 11 | 899 | 0.40 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2000 | 12 | 621 | 0.34 | 0.50 | 0.57 | 0.34 | 0.16 |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 1 | 1343 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 2 | 1075 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 3 | 1392 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 4 | | - | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 5 | 856 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 6 | 1281 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 7 | 1349 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 8 | 1465 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 9 | 1371 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 10 | 1532 | 0.61 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 11 | 1431 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2001 | 12 | 1507 | 0.58 | 0.57 | 0.61 | 0.52 | 0.06 |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 1 | 1549 | 0.60 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 2 | 1399 | 0.61 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 3 | 1532 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 4 | 1449 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 5 | 681 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 6 | 1383 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 7 | 1497 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 8 | 1374 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 9 | 1348 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 10 | 1372 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 11 | 1435 | 0.55 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2002 | 12 | 1453 | 0.54 | 0.57 | 0.61 | 0.53 | 0.04 |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 1 | 1368 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 2 | 1146 | 0.49 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 3 | 1210 | 0.50 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 4 | 769 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 5 | 111 | 0.43 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 6 | 1297 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 7 | 1379 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 8 | 1458 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 9 | 1427 | 0.58 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 10 | 1395 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 11 | 1462 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2003 | 12 | 1453 | 0.55 | 0.54 | 0.58 | 0.43 | 0.10 |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 1 | 1561 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 2 | 1244 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 3 | 1492 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 4 | 1550 | 0.62 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 5 | 885 | 0.56 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 6 | 1040 | 0.59 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 7 | 1239 | 0.61 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 8 | 1538 | 0.58 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 9 | 1406 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 10 | 1540 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 11 | 1490 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2004 | 12 | 1597 | 0.59 | 0.58 | 0.62 | 0.56 | 0.03 |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 1 | 1450 | 0.57 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 2 | 1316 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 3 | 1437 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 4 | 1262 | 0.52 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 5 | | - | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 6 | 740 | 0.51 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 7 | 1421 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 8 | 1305 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 9 | 1289 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 10 | 1357 | 0.54 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 11 | 1262 | 0.53 | | | | |
| NE | Gerald Gentleman Station | 6077 | 2 | 2005 | 12 | 1332 | 0.49 | 0.53 | 0.57 | 0.49 | 0.04 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 1 | 168 | 0.56 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 2 | 143 | 0.54 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 3 | 65 | 0.56 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 4 | 0 | 1.95 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 5 | 101 | 0.50 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 6 | 159 | 0.65 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 7 | 198 | 0.64 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 8 | 194 | 0.68 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 9 | 160 | 0.59 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 10 | 159 | 0.66 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 11 | 172 | 0.75 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1997 | 12 | 181 | 0.76 | 0.63 | 1.95 | 0.50 | 1.32 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 1 | 159 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 2 | 81 | 0.38 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 3 | 97 | 0.42 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 4 | 42 | 0.43 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 5 | 144 | 0.53 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 6 | 203 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 7 | 211 | 0.67 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 8 | 217 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 9 | 222 | 0.76 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 10 | 161 | 0.68 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 11 | 179 | 0.74 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1998 | 12 | 178 | 0.70 | 0.64 | 0.76 | 0.38 | 0.25 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 1 | 198 | 0.73 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 2 | 179 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 3 | 156 | 0.74 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 4 | 41 | 0.73 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 5 | 207 | 0.74 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 6 | 228 | 0.73 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 7 | 254 | 0.74 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 8 | 231 | 0.72 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 9 | 194 | 0.72 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 10 | 154 | 0.70 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 11 | 197 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 1999 | 12 | 212 | 0.71 | 0.72 | 0.74 | 0.70 | 0.02 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 1 | 207 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 2 | 201 | 0.70 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 3 | 213 | 0.68 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 4 | 56 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 5 | 195 | 0.64 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 6 | 192 | 0.64 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 7 | 208 | 0.64 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 8 | 179 | 0.55 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 9 | 167 | 0.58 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 10 | 155 | 0.63 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 11 | 182 | 0.62 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2000 | 12 | 210 | 0.67 | 0.64 | 0.70 | 0.55 | 0.09 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 1 | 190 | 0.62 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 2 | 176 | 0.64 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 3 | 187 | 0.64 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 4 | 110 | 0.55 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 5 | 149 | 0.61 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 6 | 148 | 0.59 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 7 | 179 | 0.54 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 8 | 222 | 0.70 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 9 | 156 | 0.55 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 10 | 153 | 0.63 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 11 | 175 | 0.62 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2001 | 12 | 162 | 0.57 | 0.61 | 0.70 | 0.54 | 0.10 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 1 | 159 | 0.56 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 2 | 145 | 0.55 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 3 | 76 | 0.52 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 4 | 27 | 0.61 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 5 | 203 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 6 | 213 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 7 | 241 | 0.75 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 8 | 201 | 0.67 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 9 | 131 | 0.72 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 10 | 182 | 0.63 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 11 | 201 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2002 | 12 | 227 | 0.77 | 0.67 | 0.77 | 0.52 | 0.14 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 1 | 187 | 0.61 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 2 | 149 | 0.54 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 3 | 151 | 0.52 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 4 | 46 | 0.48 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 5 | 164 | 0.59 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 6 | 195 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 7 | 264 | 0.82 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 8 | 240 | 0.77 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 9 | 190 | 0.70 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 10 | 152 | 0.58 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 11 | 179 | 0.61 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2003 | 12 | 237 | 0.81 | 0.66 | 0.82 | 0.48 | 0.18 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 1 | 218 | 0.74 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 2 | 220 | 0.79 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 3 | 167 | 0.56 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 4 | 78 | 0.49 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 5 | 200 | 0.66 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 6 | 202 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 7 | 225 | 0.72 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 8 | 220 | 0.70 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 9 | 205 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 10 | 173 | 0.69 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 11 | 222 | 0.72 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2004 | 12 | 221 | 0.71 | 0.69 | 0.79 | 0.49 | 0.20 |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 1 | 184 | 0.59 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 2 | 232 | 0.84 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 3 | 188 | 0.73 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 4 | 213 | 0.72 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 5 | 204 | 0.68 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 6 | 232 | 0.76 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 7 | 234 | 0.73 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 8 | 230 | 0.71 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 9 | 249 | 0.82 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 10 | 99 | 0.74 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 11 | 250 | 0.83 | | | | |
| NE | Gerald Whelan Energy Center | 60 | 1 | 2005 | 12 | 249 | 0.76 | 0.74 | 0.84 | 0.59 | 0.15 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 1 | 95 | 0.56 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 2 | 101 | 0.61 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 3 | 18 | 0.61 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 4 | - | | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 5 | 7 | 0.53 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 6 | 113 | 0.57 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 7 | 140 | 0.62 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 8 | 127 | 0.56 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 9 | 131 | 0.52 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 10 | 143 | 0.56 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 11 | 109 | 0.52 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1997 | 12 | 101 | 0.52 | 0.56 | 0.62 | 0.52 | 0.06 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 1 | 60 | 0.52 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 2 | 89 | 0.52 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 3 | 49 | 0.53 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 4 | 5 | 0.57 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 5 | 124 | 0.59 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 6 | 112 | 0.57 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 7 | 154 | 0.57 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 8 | 150 | 0.66 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 9 | 108 | 0.62 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 10 | - | | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 11 | - | | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1998 | 12 | 76 | 0.53 | 0.58 | 0.66 | 0.52 | 0.08 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 1 | 120 | 0.58 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 2 | 104 | 0.59 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 3 | 86 | 0.59 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 4 | 20 | 0.38 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 5 | 77 | 0.41 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 6 | 95 | 0.41 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 7 | 114 | 0.40 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 8 | 107 | 0.42 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 9 | 82 | 0.44 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 10 | 25 | 0.42 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 11 | 75 | 0.43 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 1999 | 12 | 84 | 0.44 | 0.46 | 0.59 | 0.38 | 0.13 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 1 | 2 | 0.40 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 2 | | - | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 3 | 0 | 0.00 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 4 | 47 | 0.43 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 5 | 105 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 6 | 90 | 0.50 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 7 | 130 | 0.60 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 8 | 97 | 0.39 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 9 | 74 | 0.38 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 10 | 76 | 0.38 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 11 | 82 | 0.53 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2000 | 12 | 138 | 0.58 | 0.48 | 0.60 | 0.00 | 0.48 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 1 | 103 | 0.52 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 2 | 115 | 0.56 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 3 | 128 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 4 | 116 | 0.52 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 5 | 4 | 0.29 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 6 | 133 | 0.56 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 7 | 128 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 8 | 138 | 0.48 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 9 | 87 | 0.44 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 10 | | - | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 11 | 59 | 0.36 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2001 | 12 | 77 | 0.38 | 0.49 | 0.56 | 0.29 | 0.20 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 1 | 77 | 0.37 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 2 | 30 | 0.40 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 3 | 75 | 0.38 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 4 | 96 | 0.40 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 5 | 96 | 0.45 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 6 | 122 | 0.48 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 7 | 118 | 0.47 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 8 | 111 | 0.46 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 9 | 79 | 0.53 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 10 | | - | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 11 | 87 | 0.48 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2002 | 12 | 85 | 0.38 | 0.44 | 0.53 | 0.37 | 0.09 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 1 | 134 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 2 | 67 | 0.45 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 3 | 98 | 0.48 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 4 | 94 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 5 | 22 | 0.39 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 6 | 75 | 0.43 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 7 | 123 | 0.42 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 8 | 141 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 9 | 75 | 0.39 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 10 | | - | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 11 | 76 | 0.40 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2003 | 12 | 111 | 0.42 | 0.45 | 0.51 | 0.39 | 0.07 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 1 | 116 | 0.45 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 2 | 105 | 0.45 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 3 | 26 | 0.42 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 4 | 108 | 0.50 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 5 | 122 | 0.49 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 6 | 146 | 0.55 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 7 | 141 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 8 | 136 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 9 | 103 | 0.42 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 10 | 64 | 0.39 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 11 | 17 | 0.32 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2004 | 12 | 98 | 0.39 | 0.47 | 0.55 | 0.32 | 0.14 |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 1 | 121 | 0.39 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 2 | 111 | 0.41 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 3 | 33 | 0.40 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 4 | 124 | 0.49 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 5 | 143 | 0.50 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 6 | 137 | 0.47 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 7 | 143 | 0.51 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 8 | 124 | 0.45 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 9 | 127 | 0.50 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 10 | 63 | 0.55 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 11 | 103 | 0.55 | | | | |
| NE | Lon D Wright Power Plant | 2240 | 8 | 2005 | 12 | 103 | 0.48 | 0.47 | 0.55 | 0.39 | 0.08 |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Nebraska City Station | 6096 | 1 | 1997 | 1 | 1442 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 2 | 1482 | 0.87 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 3 | 1575 | 0.92 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 4 | 1986 | 0.98 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 5 | 1445 | 0.81 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 6 | 1187 | 0.70 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 7 | 1207 | 0.66 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 8 | 977 | 0.55 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 9 | 376 | 0.57 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 10 | | - | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 11 | 14 | 0.44 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1997 | 12 | 541 | 0.57 | 0.76 | 0.98 | 0.44 | 0.32 |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 1 | 1001 | 0.60 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 2 | 973 | 0.68 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 3 | 1626 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 4 | 1580 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 5 | 1463 | 0.64 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 6 | 573 | 0.46 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 7 | 937 | 0.44 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 8 | 996 | 0.46 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 9 | 929 | 0.49 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 10 | 830 | 0.40 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 11 | 865 | 0.39 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1998 | 12 | 1059 | 0.45 | 0.53 | 0.69 | 0.39 | 0.16 |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 1 | 918 | 0.52 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 2 | | - | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 3 | 1490 | 0.70 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 4 | 1861 | 0.75 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 5 | 1914 | 0.75 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 6 | 1117 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 7 | 1832 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 8 | 1618 | 0.71 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 9 | 1509 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 10 | 2004 | 0.76 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 11 | 1817 | 0.75 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 1999 | 12 | 1617 | 0.74 | 0.71 | 0.76 | 0.52 | 0.19 |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 1 | 1477 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 2 | 1197 | 0.70 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 3 | 299 | 0.65 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 4 | 1371 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 5 | 1351 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 6 | 1232 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 7 | 1270 | 0.64 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 8 | 1357 | 0.63 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 9 | 1332 | 0.68 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 10 | 1527 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 11 | 1406 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2000 | 12 | 1409 | 0.65 | 0.67 | 0.72 | 0.63 | 0.05 |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 1 | 1467 | 0.68 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 2 | 879 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 3 | 1501 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 4 | 1406 | 0.66 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 5 | 1058 | 0.70 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 6 | 1345 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 7 | 1315 | 0.68 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 8 | 1370 | 0.64 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 9 | 1412 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 10 | 1614 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 11 | 1443 | 0.70 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2001 | 12 | 1396 | 0.64 | 0.68 | 0.73 | 0.64 | 0.05 |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 1 | 1258 | 0.63 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 2 | 1108 | 0.58 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 3 | 30 | 0.55 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 4 | 329 | 0.68 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 5 | 1420 | 0.64 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 6 | 1030 | 0.61 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 7 | 1429 | 0.64 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 8 | 1017 | 0.63 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 9 | 1327 | 0.66 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 10 | 1303 | 0.62 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 11 | 1193 | 0.59 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2002 | 12 | 1375 | 0.66 | 0.63 | 0.68 | 0.55 | 0.07 |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 1 | 1263 | 0.62 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 2 | 1183 | 0.60 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 3 | 1217 | 0.62 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 4 | 813 | 0.58 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 5 | 1042 | 0.55 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 6 | 1300 | 0.61 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 7 | 1547 | 0.66 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 8 | 1466 | 0.64 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 9 | 1380 | 0.63 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Nebraska City Station | 6096 | 1 | 2003 | 10 | 1448 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 11 | 1113 | 0.60 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2003 | 12 | 1280 | 0.60 | 0.62 | 0.72 | 0.55 | 0.10 |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 1 | 1425 | 0.66 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 2 | 1374 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 3 | 1480 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 4 | 1348 | 0.67 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 5 | | - | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 6 | 735 | 0.66 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 7 | 1350 | 0.65 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 8 | 1500 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 9 | 1563 | 0.74 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 10 | 1577 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 11 | 1480 | 0.69 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2004 | 12 | 1760 | 0.76 | 0.70 | 0.76 | 0.65 | 0.06 |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 1 | 1664 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 2 | 236 | 0.65 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 3 | 1663 | 0.72 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 4 | 1474 | 0.71 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 5 | 1437 | 0.74 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 6 | 1645 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 7 | 1676 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 8 | 1619 | 0.73 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 9 | 1491 | 0.74 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 10 | 1464 | 0.68 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 11 | 1537 | 0.76 | | | | |
| NE | Nebraska City Station | 6096 | 1 | 2005 | 12 | 1643 | 0.73 | 0.73 | 0.76 | 0.65 | 0.07 |
| NE | Platte | 59 | 1 | 1997 | 1 | 220 | 0.65 | | | | |
| NE | Platte | 59 | 1 | 1997 | 2 | 189 | 0.65 | | | | |
| NE | Platte | 59 | 1 | 1997 | 3 | 190 | 0.65 | | | | |
| NE | Platte | 59 | 1 | 1997 | 4 | 163 | 0.66 | | | | |
| NE | Platte | 59 | 1 | 1997 | 5 | 203 | 0.63 | | | | |
| NE | Platte | 59 | 1 | 1997 | 6 | 222 | 0.69 | | | | |
| NE | Platte | 59 | 1 | 1997 | 7 | 223 | 0.63 | | | | |
| NE | Platte | 59 | 1 | 1997 | 8 | 218 | 0.64 | | | | |
| NE | Platte | 59 | 1 | 1997 | 9 | 79 | 0.67 | | | | |
| NE | Platte | 59 | 1 | 1997 | 10 | | - | | | | |
| NE | Platte | 59 | 1 | 1997 | 11 | 119 | 0.62 | | | | |
| NE | Platte | 59 | 1 | 1997 | 12 | 180 | 0.60 | 0.64 | 0.69 | 0.60 | 0.05 |
| NE | Platte | 59 | 1 | 1998 | 1 | 278 | 0.90 | | | | |
| NE | Platte | 59 | 1 | 1998 | 2 | 217 | 0.95 | | | | |
| NE | Platte | 59 | 1 | 1998 | 3 | 236 | 0.88 | | | | |
| NE | Platte | 59 | 1 | 1998 | 4 | 200 | 0.82 | | | | |
| NE | Platte | 59 | 1 | 1998 | 5 | 163 | 0.75 | | | | |
| NE | Platte | 59 | 1 | 1998 | 6 | 190 | 0.67 | | | | |
| NE | Platte | 59 | 1 | 1998 | 7 | 241 | 0.72 | | | | |
| NE | Platte | 59 | 1 | 1998 | 8 | 273 | 0.82 | | | | |
| NE | Platte | 59 | 1 | 1998 | 9 | 250 | 0.85 | | | | |
| NE | Platte | 59 | 1 | 1998 | 10 | 185 | 0.97 | | | | |
| NE | Platte | 59 | 1 | 1998 | 11 | 259 | 0.89 | | | | |
| NE | Platte | 59 | 1 | 1998 | 12 | 292 | 0.92 | 0.84 | 0.97 | 0.67 | 0.17 |
| NE | Platte | 59 | 1 | 1999 | 1 | 244 | 0.75 | | | | |
| NE | Platte | 59 | 1 | 1999 | 2 | 188 | 0.69 | | | | |
| NE | Platte | 59 | 1 | 1999 | 3 | 228 | 0.70 | | | | |
| NE | Platte | 59 | 1 | 1999 | 4 | 179 | 0.75 | | | | |
| NE | Platte | 59 | 1 | 1999 | 5 | 233 | 0.73 | | | | |
| NE | Platte | 59 | 1 | 1999 | 6 | 216 | 0.71 | | | | |
| NE | Platte | 59 | 1 | 1999 | 7 | 323 | 0.72 | | | | |
| NE | Platte | 59 | 1 | 1999 | 8 | 241 | 0.70 | | | | |
| NE | Platte | 59 | 1 | 1999 | 9 | 201 | 0.68 | | | | |
| NE | Platte | 59 | 1 | 1999 | 10 | 130 | 0.70 | | | | |
| NE | Platte | 59 | 1 | 1999 | 11 | 191 | 0.79 | | | | |
| NE | Platte | 59 | 1 | 1999 | 12 | 188 | 0.71 | 0.72 | 0.79 | 0.68 | 0.07 |
| NE | Platte | 59 | 1 | 2000 | 1 | 236 | 0.74 | | | | |
| NE | Platte | 59 | 1 | 2000 | 2 | 208 | 0.70 | | | | |
| NE | Platte | 59 | 1 | 2000 | 3 | 195 | 0.66 | | | | |
| NE | Platte | 59 | 1 | 2000 | 4 | 199 | 0.69 | | | | |
| NE | Platte | 59 | 1 | 2000 | 5 | 252 | 0.69 | | | | |
| NE | Platte | 59 | 1 | 2000 | 6 | 215 | 0.65 | | | | |
| NE | Platte | 59 | 1 | 2000 | 7 | 212 | 0.56 | | | | |
| NE | Platte | 59 | 1 | 2000 | 8 | 213 | 0.57 | | | | |
| NE | Platte | 59 | 1 | 2000 | 9 | 89 | 0.61 | | | | |
| NE | Platte | 59 | 1 | 2000 | 10 | 180 | 0.79 | | | | |
| NE | Platte | 59 | 1 | 2000 | 11 | 255 | 0.66 | | | | |
| NE | Platte | 59 | 1 | 2000 | 12 | 243 | 0.61 | 0.66 | 0.79 | 0.56 | 0.14 |
| NE | Platte | 59 | 1 | 2001 | 1 | 237 | 0.63 | | | | |
| NE | Platte | 59 | 1 | 2001 | 2 | 214 | 0.61 | | | | |
| NE | Platte | 59 | 1 | 2001 | 3 | 203 | 0.60 | | | | |
| NE | Platte | 59 | 1 | 2001 | 4 | 236 | 0.62 | | | | |
| NE | Platte | 59 | 1 | 2001 | 5 | 200 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2001 | 6 | 216 | 0.64 | | | | |

Region 7 Public Power
SO2 Data
1997-2005

| STATE | FACILITY_NAME | ORISPL_C | UNITID | OP_YEAR | OP_MONTH | SO2 Mass | SO2 Rate | Average | Max Rate | Min Rate | Max Difference from Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NE | Platte | 59 | 1 | 2001 | 7 | 225 | 0.61 | | | | |
| NE | Platte | 59 | 1 | 2001 | 8 | 216 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2001 | 9 | 167 | 0.56 | | | | |
| NE | Platte | 59 | 1 | 2001 | 10 | 136 | 0.55 | | | | |
| NE | Platte | 59 | 1 | 2001 | 11 | 187 | 0.60 | | | | |
| NE | Platte | 59 | 1 | 2001 | 12 | 198 | 0.58 | 0.60 | 0.64 | 0.55 | 0.05 |
| NE | Platte | 59 | 1 | 2002 | 1 | 221 | 0.64 | | | | |
| NE | Platte | 59 | 1 | 2002 | 2 | 182 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2002 | 3 | 271 | 0.69 | | | | |
| NE | Platte | 59 | 1 | 2002 | 4 | 174 | 0.65 | | | | |
| NE | Platte | 59 | 1 | 2002 | 5 | 242 | 0.69 | | | | |
| NE | Platte | 59 | 1 | 2002 | 6 | 193 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2002 | 7 | 231 | 0.60 | | | | |
| NE | Platte | 59 | 1 | 2002 | 8 | 215 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2002 | 9 | 155 | 0.58 | | | | |
| NE | Platte | 59 | 1 | 2002 | 10 | 0 | 0.07 | | | | |
| NE | Platte | 59 | 1 | 2002 | 11 | 145 | 0.64 | | | | |
| NE | Platte | 59 | 1 | 2002 | 12 | 220 | 0.60 | 0.62 | 0.69 | 0.07 | 0.55 |
| NE | Platte | 59 | 1 | 2003 | 1 | 193 | 0.51 | | | | |
| NE | Platte | 59 | 1 | 2003 | 2 | 191 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2003 | 3 | 217 | 0.56 | | | | |
| NE | Platte | 59 | 1 | 2003 | 4 | 167 | 0.55 | | | | |
| NE | Platte | 59 | 1 | 2003 | 5 | 200 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2003 | 6 | 179 | 0.53 | | | | |
| NE | Platte | 59 | 1 | 2003 | 7 | 197 | 0.52 | | | | |
| NE | Platte | 59 | 1 | 2003 | 8 | 193 | 0.52 | | | | |
| NE | Platte | 59 | 1 | 2003 | 9 | 173 | 0.55 | | | | |
| NE | Platte | 59 | 1 | 2003 | 10 | 105 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2003 | 11 | 179 | 0.51 | | | | |
| NE | Platte | 59 | 1 | 2003 | 12 | 199 | 0.54 | 0.53 | 0.56 | 0.51 | 0.03 |
| NE | Platte | 59 | 1 | 2004 | 1 | 207 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2004 | 2 | 197 | 0.52 | | | | |
| NE | Platte | 59 | 1 | 2004 | 3 | 210 | 0.55 | | | | |
| NE | Platte | 59 | 1 | 2004 | 4 | 162 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2004 | 5 | 196 | 0.53 | | | | |
| NE | Platte | 59 | 1 | 2004 | 6 | 169 | 0.49 | | | | |
| NE | Platte | 59 | 1 | 2004 | 7 | 168 | 0.46 | | | | |
| NE | Platte | 59 | 1 | 2004 | 8 | 176 | 0.50 | | | | |
| NE | Platte | 59 | 1 | 2004 | 9 | 177 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2004 | 10 | 90 | 0.49 | | | | |
| NE | Platte | 59 | 1 | 2004 | 11 | 173 | 0.51 | | | | |
| NE | Platte | 59 | 1 | 2004 | 12 | 235 | 0.64 | 0.53 | 0.64 | 0.46 | 0.11 |
| NE | Platte | 59 | 1 | 2005 | 1 | 210 | 0.54 | | | | |
| NE | Platte | 59 | 1 | 2005 | 2 | 189 | 0.55 | | | | |
| NE | Platte | 59 | 1 | 2005 | 3 | 181 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2005 | 4 | 225 | 0.62 | | | | |
| NE | Platte | 59 | 1 | 2005 | 5 | 228 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2005 | 6 | 214 | 0.58 | | | | |
| NE | Platte | 59 | 1 | 2005 | 7 | 230 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2005 | 8 | 229 | 0.60 | | | | |
| NE | Platte | 59 | 1 | 2005 | 9 | 215 | 0.62 | | | | |
| NE | Platte | 59 | 1 | 2005 | 10 | 152 | 0.59 | | | | |
| NE | Platte | 59 | 1 | 2005 | 11 | 192 | 0.58 | | | | |
| NE | Platte | 59 | 1 | 2005 | 12 | 212 | 0.62 | 0.59 | 0.62 | 0.54 | 0.04 |
| | | | | | | 505034 | | 0.59 | | | |

| Percentile of Monthly SO2 Rates | |
|---|---|
| 50 | 0.57 |
| 95 | 0.81 |
| 97 | 0.82 |
| 99 | 0.90 |
| 99.5 | 0.96 |
| 100 | 1.95 |

**Attachment D**
**Sunflower Holcomb**
**Summary of Subpart Da Emission Reports**
**from July '98 through June '06**

Sunflower Electric Cooperative
Holcomb Unit H1

| Occurrence of Inlet Coal SO2 Concentrations (30-day average) above… | | | | Occurrence of Outlet SO2 Concentrations (30-day average) above… | | | | Occurrence of SO2 Percent Removal (30-day average) above… | | | | Occurrence of NOx Concentrations (30-day average) above… | | | | Occurrence of CO Concentrations (30-day average) above… | | | | Occurrence of Outlet SO2 at "Hypothetical" 90% Removal (30-day average) above… | | | | Occurrence of Outlet SO2 at "Hypothetical" 92% Removal (30-day average) above… | | | | Occurrence of Outlet SO2 at "Hypothetical" 94% Removal (30-day average) above… | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Inlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | % Removal | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet NOx | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet CO | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence |
| 1.50 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.45 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.40 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.35 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.30 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.25 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.20 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.15 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.10 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.05 | - | - | - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1.00 | - | - | - | | | | | 100.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.99 | - | - | - | | | | | 99.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.98 | - | - | - | | | | | 98.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.97 | - | - | - | | | | | 97.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.96 | - | - | - | | | | | 96.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.95 | 0.1% | 99.9% | 0.1% | | | | | 95.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.94 | 0.2% | 99.8% | 0.1% | | | | | 94.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.93 | 0.3% | 99.7% | 0.4% | | | | | 93.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.92 | 0.7% | 99.3% | 0.6% | | | | | 92.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.91 | 1.3% | 98.7% | 0.7% | | | | | 91.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.90 | 2.0% | 98.0% | 0.9% | | | | | 90.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.89 | 2.9% | 97.1% | 1.3% | | | | | 89.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.88 | 4.2% | 95.8% | 1.1% | | | | | 88.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.87 | 5.3% | 94.7% | 0.7% | | | | | 87.0% | 0.0% | 100.0% | 2.4% | | | | | | | | | | | | | | | | | | | | |
| 0.86 | 6.0% | 94.0% | 1.5% | | | | | 86.0% | 2.4% | 97.6% | 4.3% | | | | | | | | | | | | | | | | | | | | |
| 0.85 | 7.5% | 92.5% | 1.5% | | | | | 85.0% | 6.7% | 93.3% | 4.3% | | | | | | | | | | | | | | | | | | | | |
| 0.84 | 9.0% | 91.0% | 1.6% | | | | | 84.0% | 11.0% | 89.0% | 4.7% | | | | | | | | | | | | | | | | | | | | |
| 0.83 | 10.6% | 89.4% | 2.2% | | | | | 83.0% | 15.7% | 84.3% | 4.2% | | | | | | | | | | | | | | | | | | | | |
| 0.82 | 12.8% | 87.2% | 2.4% | | | | | 82.0% | 19.9% | 80.1% | 6.3% | | | | | | | | | | | | | | | | | | | | |
| 0.81 | 15.2% | 84.8% | 3.3% | | | | | 81.0% | 26.2% | 73.8% | 8.5% | | | | | | | | | | | | | | | | | | | | |
| 0.80 | 18.5% | 81.5% | 3.4% | | | | | 80.0% | 34.7% | 65.3% | 8.3% | | | | | | | | | | | | | | | | | | | | |
| 0.79 | 21.9% | 78.1% | 3.0% | | | | | 79.0% | 43.0% | 57.0% | 10.4% | | | | | | | | | | | | | | | | | | | | |
| 0.78 | 24.9% | 75.1% | 3.5% | | | | | 78.0% | 53.4% | 46.6% | 7.0% | | | | | | | | | | | | | | | | | | | | |
| 0.77 | 28.4% | 71.6% | 2.5% | | | | | 77.0% | 60.4% | 39.6% | 6.8% | | | | | | | | | | | | | | | | | | | | |
| 0.76 | 30.9% | 69.1% | 1.6% | | | | | 76.0% | 67.2% | 32.8% | 14.8% | | | | | | | | | | | | | | | | | | | | |
| 0.75 | 32.5% | 67.5% | 1.3% | | | | | 75.0% | 82.0% | 18.0% | 14.1% | | | | | | | | | | | | | | | | | | | | |
| 0.74 | 33.8% | 66.2% | 1.8% | | | | | 74.0% | 96.1% | 3.9% | 3.6% | | | | | | | | | | | | | | | | | | | | |
| 0.73 | 35.6% | 64.4% | 1.0% | | | | | 73.0% | 99.7% | 0.3% | 0.3% | | | | | | | | | | | | | | | | | | | | |
| 0.72 | 36.6% | 63.4% | 1.5% | | | | | 72.0% | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | | | | | |
| 0.71 | 38.1% | 61.9% | 0.5% | | | | | 71.0% | 100.0% | 0.0% | - | | | | | | | | | | | | | | | | | | | | |
| 0.70 | 38.6% | 61.4% | 0.7% | | | | | 70.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.69 | 39.3% | 60.7% | 2.3% | | | | | 69.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.68 | 41.6% | 58.4% | 3.9% | | | | | 68.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.67 | 45.5% | 54.5% | 6.4% | | | | | 67.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.66 | 51.9% | 48.1% | 8.6% | | | | | 66.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.65 | 60.5% | 39.5% | 8.5% | | | | | 65.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.64 | 69.0% | 31.0% | 7.4% | | | | | 64.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.63 | 76.4% | 23.6% | 8.4% | | | | | 63.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.62 | 84.8% | 15.2% | 6.4% | | | | | 62.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.61 | 91.2% | 8.8% | 3.4% | | | | | 61.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.60 | 94.6% | 5.4% | 2.4% | | | | | 60.0% | - | - | - | | | | | | | | | | | | | | | | | | | | |
| 0.59 | 97.0% | 3.0% | 1.6% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.58 | 98.6% | 1.4% | 0.8% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.57 | 99.4% | 0.6% | 0.5% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.56 | 99.9% | 0.1% | 0.1% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.55 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.54 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.53 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.52 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.51 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 0.50 | 100.0% | 0.0% | - | 0.50 | - | - | - | | | | | 0.50 | - | - | - | | | | | | | | | | | | | | | | |
| 0.49 | - | - | - | 0.49 | - | - | - | | | | | 0.49 | - | - | - | | | | | | | | | | | | | | | | |
| 0.48 | - | - | - | 0.48 | - | - | - | | | | | 0.48 | - | - | - | | | | | | | | | | | | | | | | |
| 0.47 | - | - | - | 0.47 | - | - | - | | | | | 0.47 | - | - | - | | | | | | | | | | | | | | | | |
| 0.46 | - | - | - | 0.46 | - | - | - | | | | | 0.46 | - | - | - | | | | | | | | | | | | | | | | |
| 0.45 | - | - | - | 0.45 | - | - | - | | | | | 0.45 | - | - | - | | | | | | | | | | | | | | | | |
| 0.44 | - | - | - | 0.44 | - | - | - | | | | | 0.44 | - | - | - | | | | | | | | | | | | | | | | |
| 0.43 | - | - | - | 0.43 | - | - | - | | | | | 0.43 | - | - | - | | | | | | | | | | | | | | | | |
| 0.42 | - | - | - | 0.42 | - | - | - | | | | | 0.42 | - | - | - | | | | | | | | | | | | | | | | |
| 0.41 | - | - | - | 0.41 | - | - | - | | | | | 0.41 | - | - | - | | | | | | | | | | | | | | | | |
| 0.40 | - | - | - | 0.40 | - | - | - | | | | | 0.40 | - | - | - | | | | | | | | | | | | | | | | |
| 0.39 | - | - | - | 0.39 | - | - | - | | | | | 0.39 | - | - | - | | | | | | | | | | | | | | | | |
| 0.38 | - | - | - | 0.38 | - | - | - | | | | | 0.38 | - | - | - | | | | | | | | | | | | | | | | |
| 0.37 | - | - | - | 0.37 | - | - | - | | | | | 0.37 | - | - | - | | | | | | | | | | | | | | | | |
| 0.36 | - | - | - | 0.36 | - | - | - | | | | | 0.36 | - | - | - | | | | | | | | | | | | | | | | |
| 0.35 | - | - | - | 0.35 | - | - | - | | | | | 0.35 | - | - | - | | | | | | | | | | | | | | | | |
| | | | | 0.34 | - | - | - | | | | | 0.34 | 0.2% | 99.8% | 4.4% | | | | | | | | | | | | | | | | |
| | | | | 0.33 | - | - | - | | | | | 0.33 | 4.6% | 95.4% | 13.8% | | | | | | | | | | | | | | | | |
| | | | | 0.32 | - | - | - | | | | | 0.32 | 18.4% | 81.6% | 7.5% | | | | | | | | | | | | | | | | |
| | | | | 0.31 | - | - | - | | | | | 0.31 | 25.9% | 74.1% | 10.1% | | | | | | | | | | | | | | | | |
| | | | | 0.30 | - | - | - | | | | | 0.30 | 36.0% | 64.0% | 6.5% | | | | | | | | | | | | | | | | |
| | | | | 0.29 | - | - | - | | | | | 0.29 | 42.5% | 57.5% | 14.6% | | | | | | | | | | | | | | | | |
| | | | | 0.28 | - | - | - | | | | | 0.28 | 57.1% | 42.9% | 22.6% | | | | | | | | | | | | | | | | |
| | | | | 0.27 | - | - | - | | | | | 0.27 | 79.7% | 20.3% | 16.0% | | | | | | | | | | | | | | | | |
| | | | | 0.26 | - | - | - | | | | | 0.26 | 95.7% | 4.3% | 4.2% | | | | | | | | | | | | | | | | |
| | | | | 0.25 | - | - | - | | | | | 0.25 | 99.9% | 0.1% | 0.0% | | | | | | | | | | | | | | | | |
| | | | | 0.24 | - | - | - | | | | | 0.24 | 99.9% | 0.1% | 0.1% | | | | | | | | | | | | | | | | |
| | | | | 0.23 | - | - | - | | | | | 0.23 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | |
| | | | | 0.22 | - | - | - | | | | | 0.22 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | |
| | | | | 0.21 | 0.2% | 99.8% | 0.3% | | | | | 0.21 | 100.0% | 0.0% | 0.0% | | | | | | | | | | | | | | | | |
| | | | | 0.20 | 0.5% | 99.5% | 1.4% | | | | | 0.20 | 100.0% | 0.0% | - | 0.20 | - | - | - | 0.200 | - | - | - | 0.200 | - | - | - | 0.200 | - | - | - |
| | | | | 0.19 | 1.9% | 98.1% | 4.0% | | | | | 0.19 | - | - | - | 0.19 | - | - | - | 0.190 | - | - | - | 0.190 | - | - | - | 0.190 | - | - | - |
| | | | | 0.18 | 5.9% | 94.1% | 11.1% | | | | | 0.18 | - | - | - | 0.18 | - | - | - | 0.180 | - | - | - | 0.180 | - | - | - | 0.180 | - | - | - |
| | | | | 0.17 | 17.0% | 83.0% | 21.5% | | | | | 0.17 | - | - | - | 0.17 | - | - | - | 0.170 | - | - | - | 0.170 | - | - | - | 0.170 | - | - | - |
| | | | | 0.16 | 38.5% | 61.5% | 18.7% | | | | | 0.16 | - | - | - | 0.16 | - | - | - | 0.160 | - | - | - | 0.160 | - | - | - | 0.160 | - | - | - |
| | | | | 0.15 | 57.2% | 42.8% | 11.2% | | | | | 0.15 | - | - | - | 0.15 | - | - | - | 0.150 | - | - | - | 0.150 | - | - | - | 0.150 | - | - | - |
| | | | | 0.14 | 68.4% | 31.6% | 8.1% | | | | | 0.14 | - | - | - | 0.14 | - | - | - | 0.140 | - | - | - | 0.140 | - | - | - | 0.140 | - | - | - |

Sunflower Electric Cooperative
Holcomb Unit H1

| Occurrence of Inlet Coal SO2 Concentrations (30-day average) above… | | | | Occurrence of Outlet SO2 Concentrations (30-day average) above… | | | | Occurrence of SO2 Percent Removal (30-day average) above… | | | | Occurrence of NOx Concentrations (30-day average) above… | | | | Occurrence of CO Concentrations (30-day average) above… | | | | Occurrence of Outlet SO2 at "Hypothetical" 90% Removal (30-day average) above… | | | | Occurrence of Outlet SO2 at "Hypothetical" 92% Removal (30-day average) above… | | | | Occurrence of Outlet SO2 at "Hypothetical" 94% Removal (30-day average) above… | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Inlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | % Removal | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet NOx | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet CO | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence | Outlet SO2 | Cumulative Occurrence (ascending) | Cumulative Occurrence (descending) | Individual Occurrence |
| | | | | 0.13 | 76.5% | 23.5% | 8.9% | | | | | 0.13 | - | - | - | 0.13 | - | - | - | 0.130 | - | - | - | 0.130 | - | - | - | 0.130 | - | - | - |
| | | | | 0.12 | 85.4% | 14.6% | 8.1% | | | | | 0.12 | - | - | - | 0.12 | - | - | - | 0.120 | - | - | - | 0.120 | - | - | - | 0.120 | - | - | - |
| | | | | 0.11 | 93.5% | 6.5% | 4.4% | | | | | 0.11 | - | - | - | 0.11 | - | - | - | 0.110 | - | - | - | 0.110 | - | - | - | 0.110 | - | - | - |
| | | | | 0.10 | 97.9% | 2.1% | 0.6% | | | | | 0.10 | - | - | - | 0.10 | - | - | - | 0.100 | - | - | - | 0.100 | - | - | - | 0.100 | - | - | - |
| | | | | 0.09 | 98.5% | 1.5% | - | | | | | 0.09 | - | - | - | 0.09 | - | - | - | 0.090 | 2.0% | 98.0% | 16.3% | 0.090 | - | - | - | 0.090 | - | - | - |
| | | | | 0.08 | - | - | - | | | | | 0.08 | - | - | - | 0.08 | - | - | - | 0.080 | 18.3% | 81.7% | 20.2% | 0.075 | 0.2% | 99.8% | 4.4% | 0.080 | - | - | - |
| | | | | 0.07 | - | - | - | | | | | 0.07 | - | - | - | 0.07 | - | - | - | 0.070 | 38.5% | 61.5% | 55.8% | 0.070 | 4.6% | 95.4% | 27.8% | 0.070 | - | - | - |
| | | | | 0.06 | - | - | - | | | | | 0.06 | - | - | - | 0.06 | - | - | - | 0.060 | 94.3% | 5.7% | 5.6% | 0.060 | 32.4% | 67.6% | 46.8% | 0.060 | - | - | - |
| | | | | 0.05 | - | - | - | | | | | 0.05 | - | - | - | 0.05 | - | - | - | 0.050 | 99.9% | 0.1% | 0.0% | 0.050 | 79.2% | 20.8% | 20.7% | 0.050 | 9.9% | 90.1% | 36.9% |
| | | | | 0.04 | - | - | - | | | | | 0.04 | - | - | - | 0.04 | 2.9% | 97.1% | 41.4% | 0.040 | 99.9% | 0.1% | 0.0% | 0.040 | 99.9% | 0.1% | 0.0% | 0.040 | 46.8% | 53.2% | 53.1% |
| | | | | 0.03 | - | - | - | | | | | 0.03 | - | - | - | 0.03 | 44.3% | 55.7% | 50.7% | 0.030 | 99.9% | 0.1% | 0.0% | 0.030 | 99.9% | 0.1% | 0.0% | 0.030 | 99.9% | 0.1% | 0.0% |
| | | | | 0.02 | - | - | - | | | | | 0.02 | - | - | - | 0.02 | 95.0% | 5.0% | - | 0.020 | 99.9% | 0.1% | 0.0% | 0.020 | 99.9% | 0.1% | 0.0% | 0.020 | 99.9% | 0.1% | 0.0% |
| | | | | 0.01 | - | - | - | | | | | 0.01 | - | - | - | 0.01 | - | - | - | 0.010 | 99.9% | 0.1% | 0.1% | 0.010 | 99.9% | 0.1% | 0.1% | 0.010 | 99.9% | 0.1% | 0.1% |
| | | | | 0.00 | - | - | - | | | | | 0.00 | - | - | - | 0.00 | - | - | - | 0.000 | 100.0% | 0.0% | - | 0.000 | 100.0% | 0.0% | - | 0.000 | 100.0% | 0.0% | - |

Sunflower Electric Cooperative
Holcomb Unit H1
SO2 Emissions Scrubber Performance

| Year | Quarter | SO2 Emissions, #/mmBtu | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 0.05 | 0.06 | 0.07 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 | 0.16 | 0.17 | 0.18 | 0.19 | 0.20 | 0.21 | 0.22 | 0.23 | 0.24 | 0.25 | 0.26 | 0.27 | 0.28 | 0.29 | 0.30 |
| 1998 | 1 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1998 | 2 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1998 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 42% | 61% | 87% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 1998 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 10% | 55% | 88% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 1999 | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 9% | 38% | 88% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 1999 | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 4% | 24% | 70% | 97% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 1999 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 5% | 16% | 42% | 60% | 82% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 1999 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 25% | 83% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2000 | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 13% | 33% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2000 | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 9% | 41% | 67% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2000 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 8% | 20% | 33% | 84% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2000 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 45% | 87% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2001 | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 27% | 77% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2001 | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 27% | 87% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2001 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 56% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2001 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 46% | 58% | 72% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 30% | 57% | 91% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 30% | 57% | 91% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 36% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 34% | 60% | 70% | 81% | 90% | 97% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 17% | 37% | 68% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 2% | 13% | 38% | 71% | 91% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 9% | 14% | 51% | 77% | 91% | 99% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 7% | 40% | 81% | 95% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 29% | 73% | 96% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 7% | 40% | 58% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 4% | 26% | 52% | 61% | 72% | 81% | 96% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 5% | 33% | 68% | 76% | 77% | 83% | 95% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 1 | 0% | 0% | 0% | 0% | 0% | 1% | 18% | 39% | 57% | 90% | 91% | 91% | 99% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 2 | 0% | 0% | 0% | 0% | 0% | 5% | 29% | 30% | 40% | 54% | 67% | 81% | 98% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 3 | 0% | 0% | 0% | 0% | 0% | 8% | 44% | 64% | 78% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 4% | 37% | 72% | 84% | 97% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2006 | 1 | 0% | 0% | 0% | 13% | 50% | 60% | 75% | 90% | 96% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2006 | 2 | 0% | 0% | 0% | 34% | 36% | 36% | 60% | 94% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2006 | 3 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 2006 | 4 | | | | | | | | | | | | | | | | | | | | | | | | | | |

| Year | Quarter | SO2 % Removal | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 67 | 68 | 69 | 70 | 71 | 72 | 73 | 74 | 75 | 76 | 77 | 78 | 79 | 80 | 81 | 82 | 83 | 84 | 85 | 86 | 87 | 88 | 89 | 90 | 91 | 92 | 93 | 94 | 95 | 96 |
| 1998 | 1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1998 | 2 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1998 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 92% | 66% | 42% | 11% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1998 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 81% | 67% | 50% | 17% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1999 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 90% | 86% | 66% | 35% | 10% | 9% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1999 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 92% | 44% | 18% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1999 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 90% | 49% | 36% | 10% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1999 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 99% | 53% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2000 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 44% | 10% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2000 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 74% | 52% | 12% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2000 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 60% | 24% | 19% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2000 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 79% | 25% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2001 | 1 | 100% | 100% | 100% | 100% | 100% | 99% | 99% | 95% | 64% | 20% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2001 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 69% | 31% | 17% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2001 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 93% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2001 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 92% | 72% | 62% | 32% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2002 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 88% | 61% | 36% | 16% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2002 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 88% | 61% | 36% | 16% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2002 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 86% | 33% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2002 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 92% | 73% | 58% | 32% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2003 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 66% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2003 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 99% | 80% | 30% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2003 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 92% | 68% | 42% | 10% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2003 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 85% | 24% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 94% | 90% | 64% | 52% | 32% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 91% | 58% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 82% | 71% | 61% | 58% | 38% | 6% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 95% | 78% | 77% | 76% | 76% | 61% | 32% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 91% | 91% | 91% | 90% | 84% | 53% | 21% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 83% | 59% | 54% | 51% | 43% | 8% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 82% | 71% | 63% | 38% | 10% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 94% | 57% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2006 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 97% | 91% | 9% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2006 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 81% | 38% | 36% | 34% | 19% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2006 | 3 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
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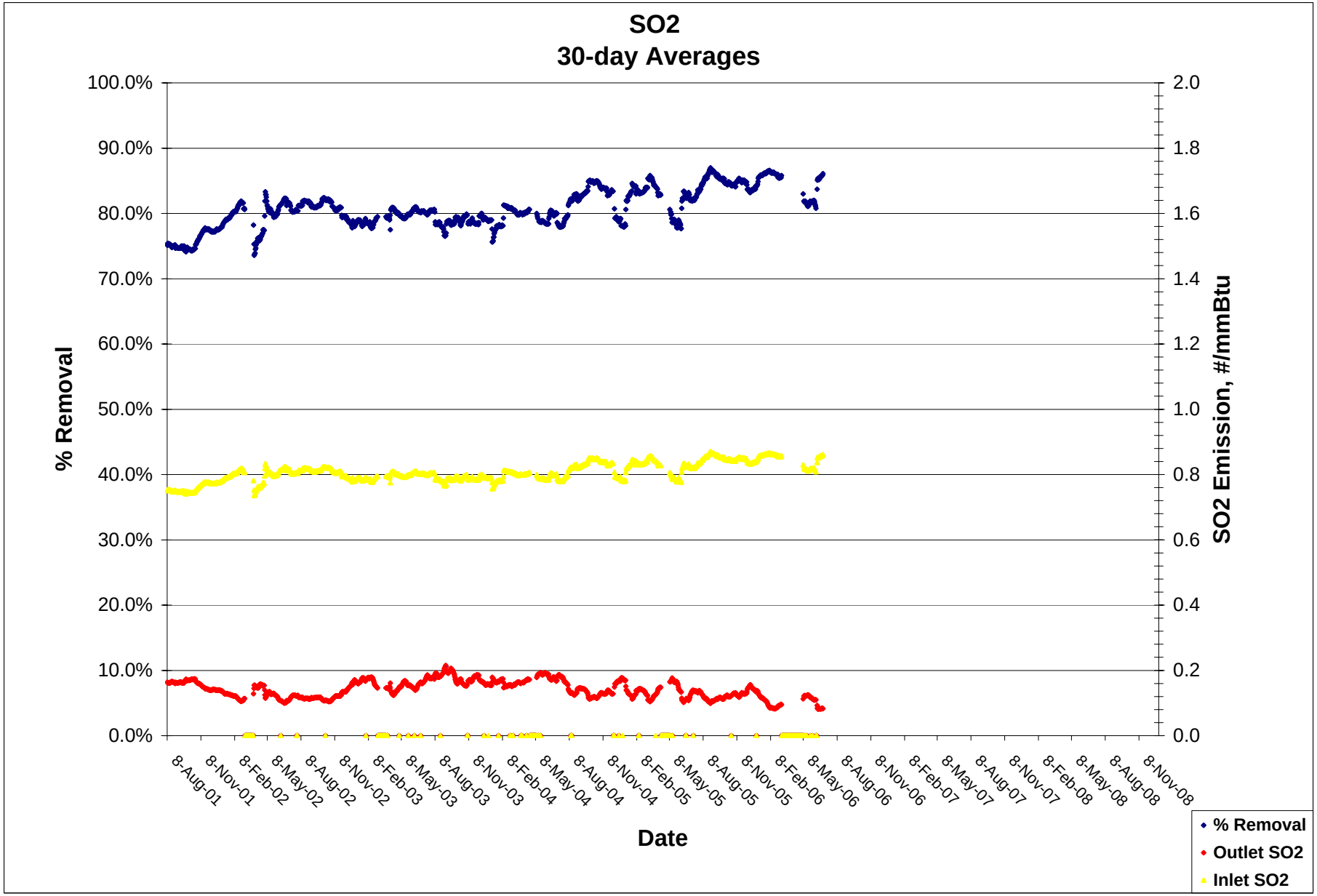
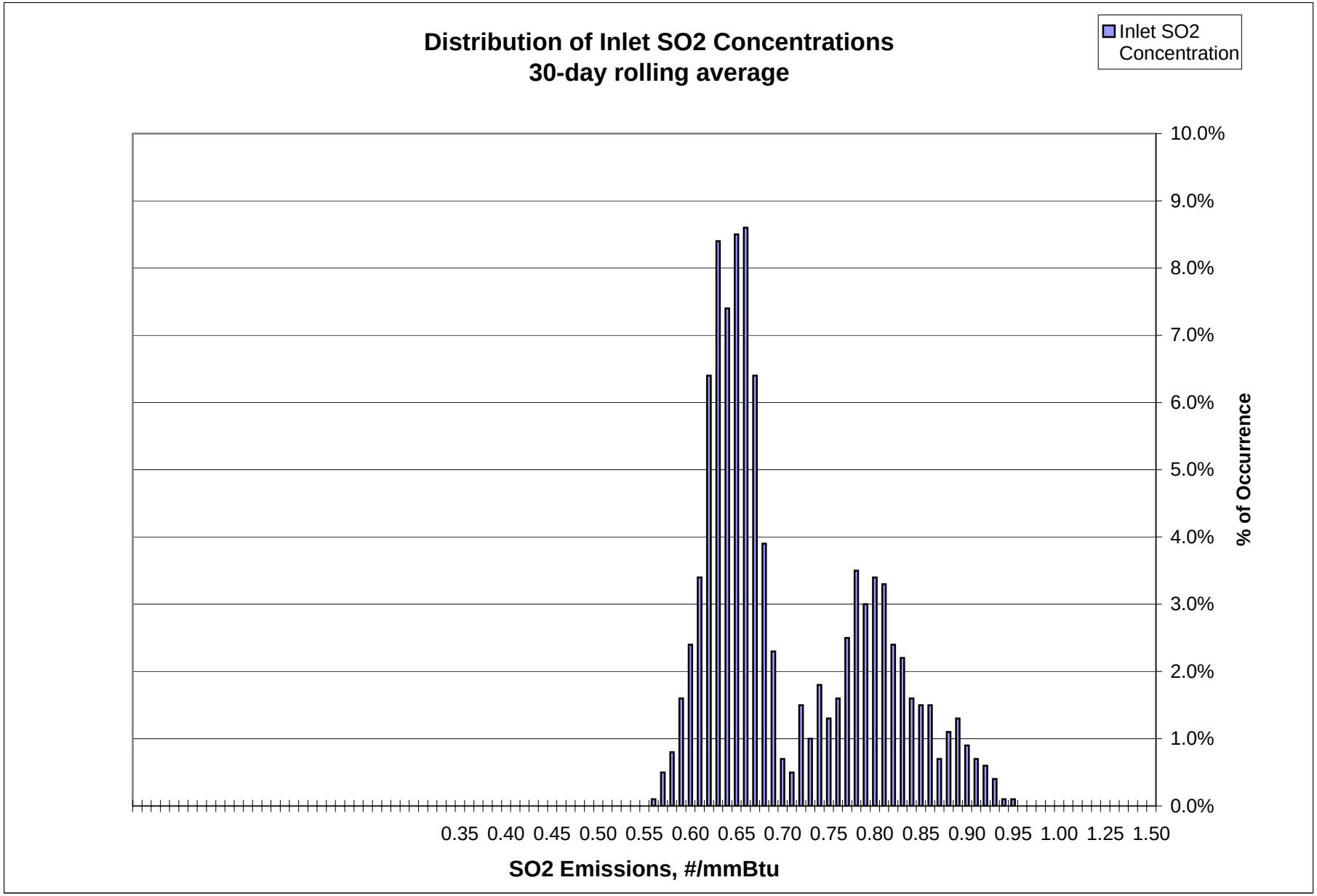
Sunflower Electric Cooperative
Holcomb Unit H1



Sunflower Electric Cooperative
Holcomb Unit H1



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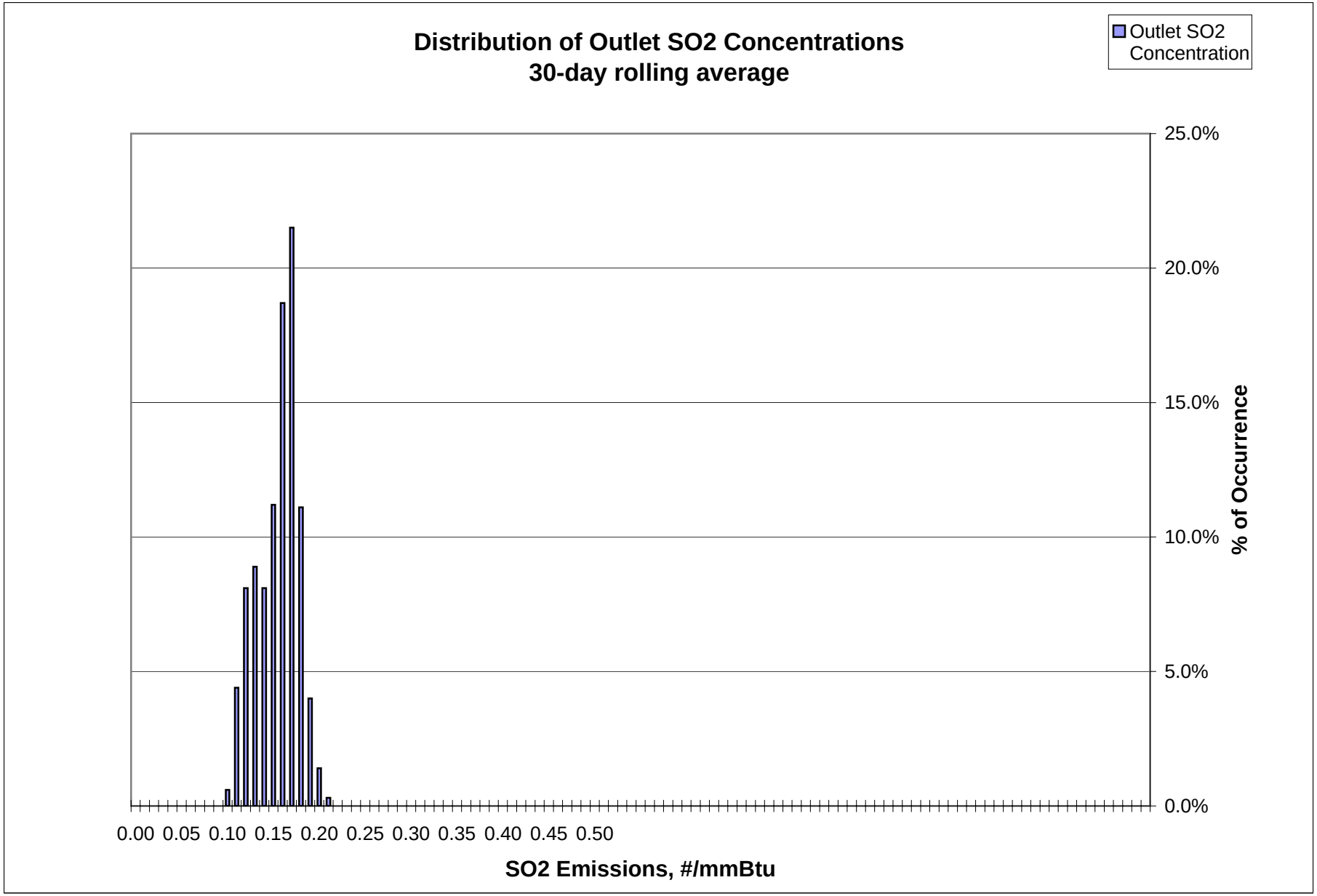
Holcomb Unit H1



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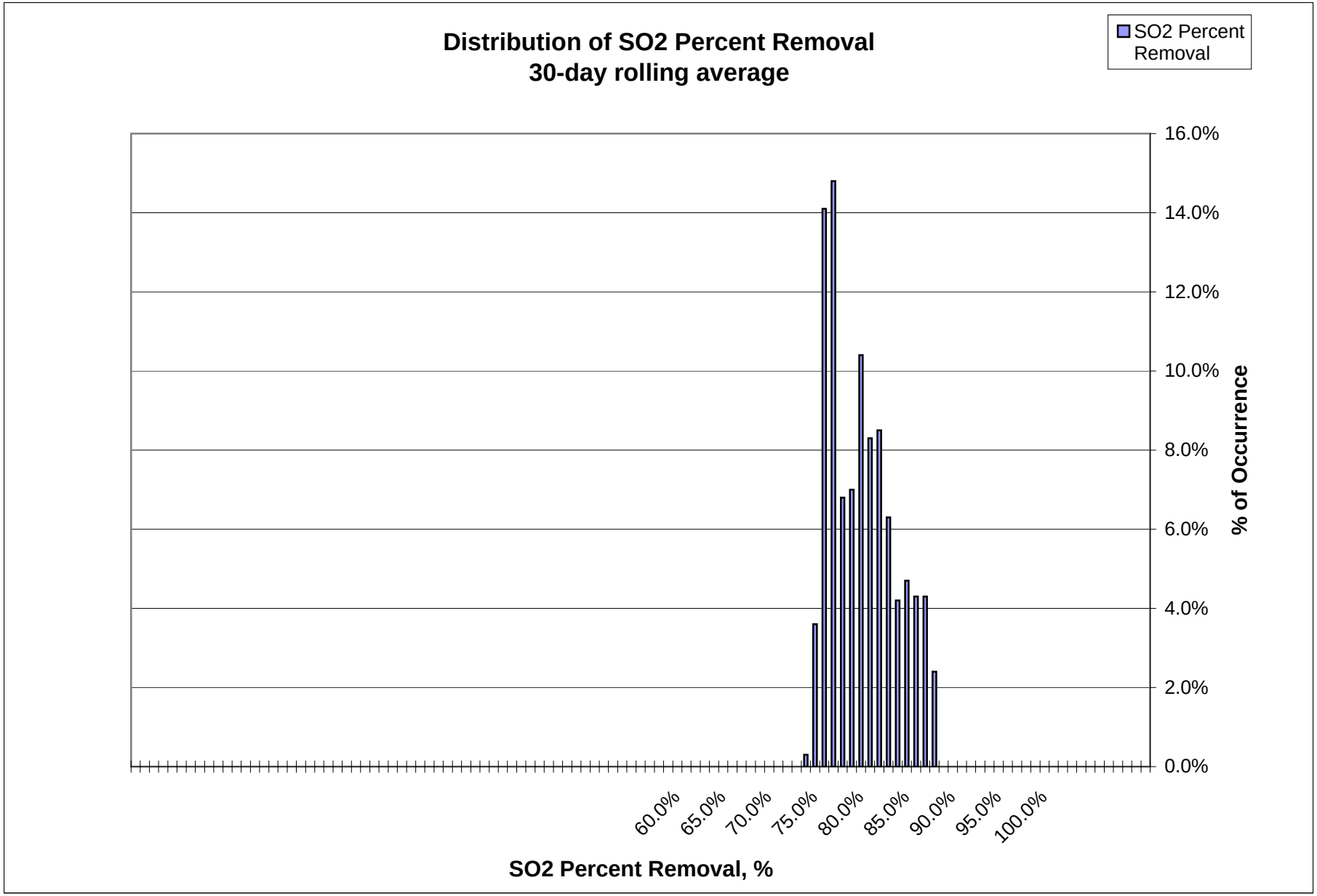

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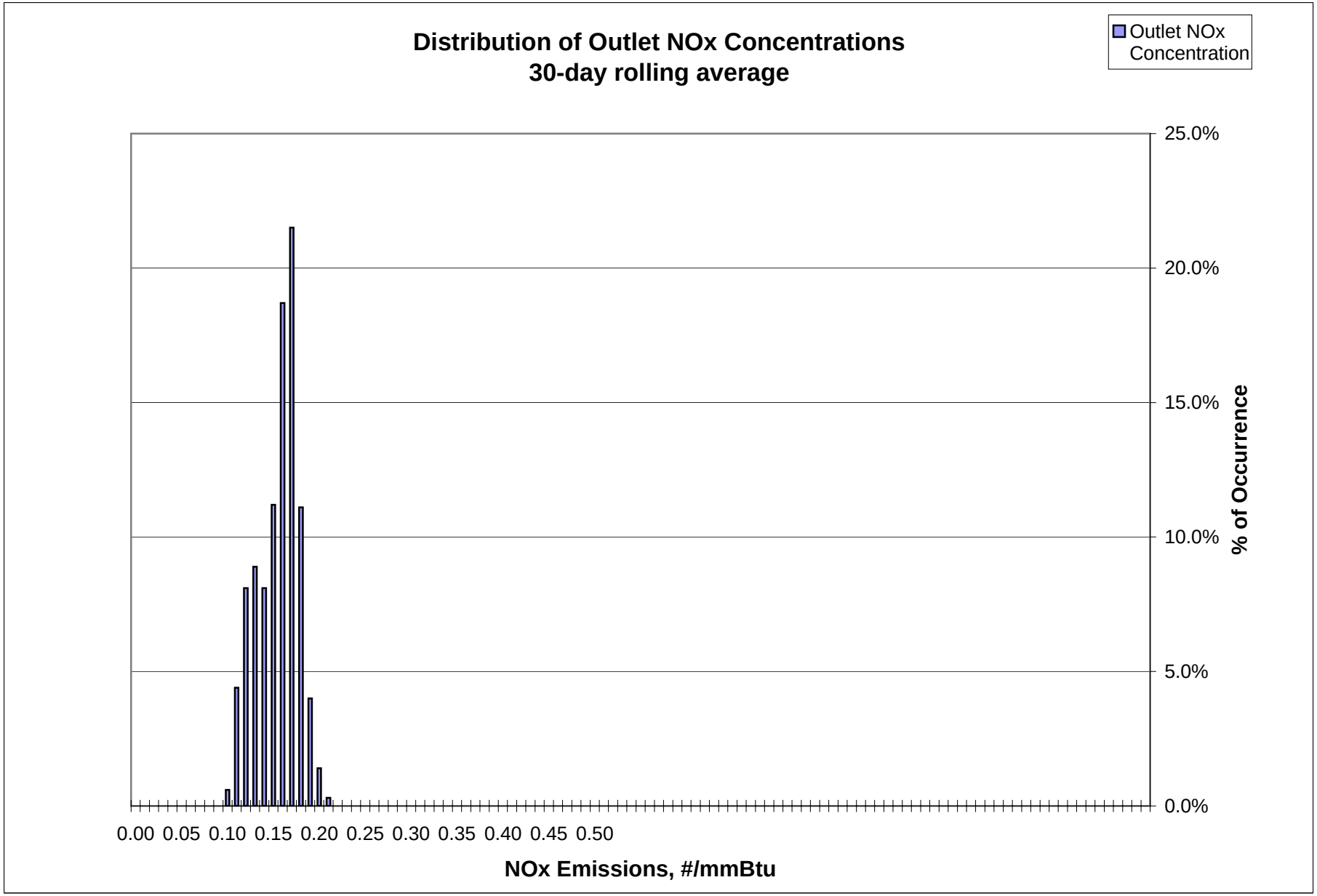
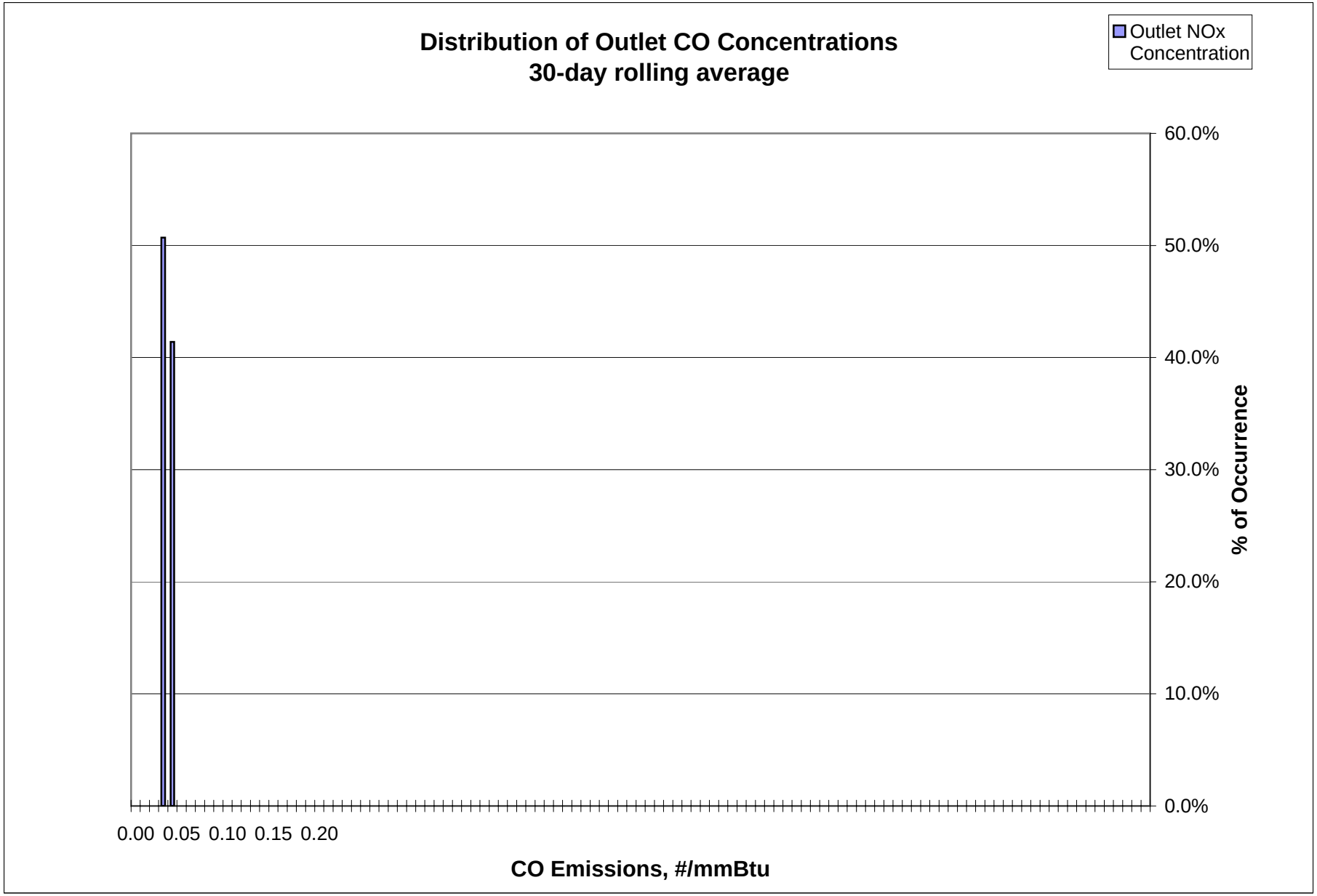
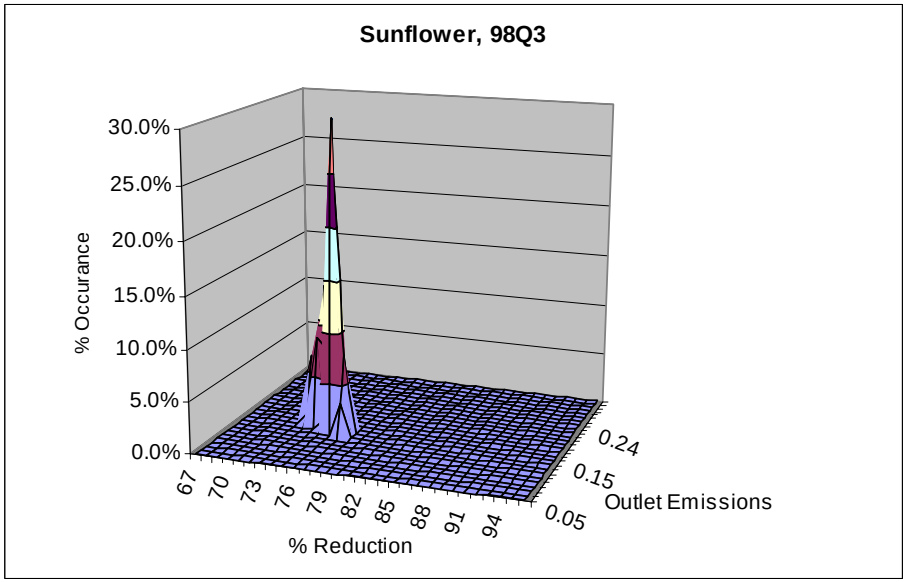
Holcomb Unit H1



Sunflower Electric Cooperative
Holcomb Unit H1




Sunflower, 98Q3
30.0%
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% Reduction
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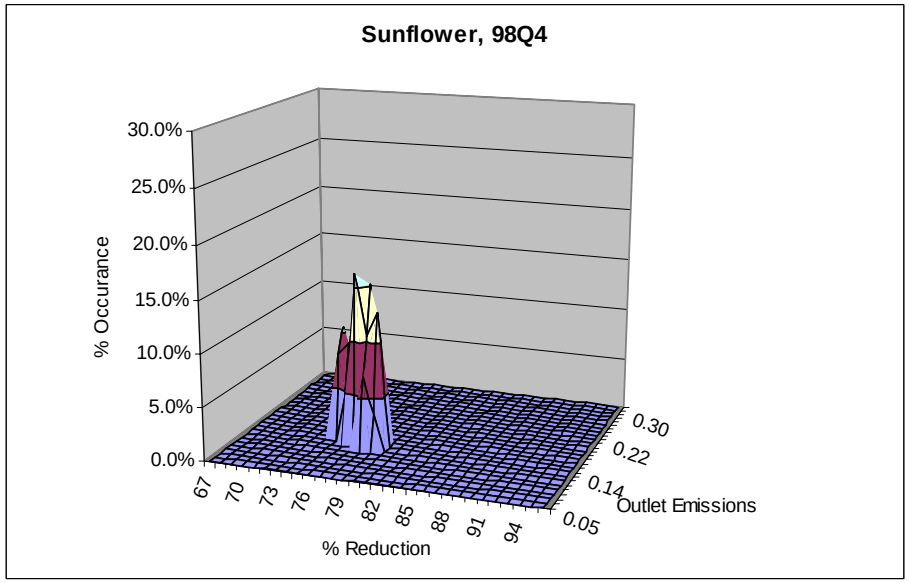
Outlet Emissions


Sunflower, 98Q4
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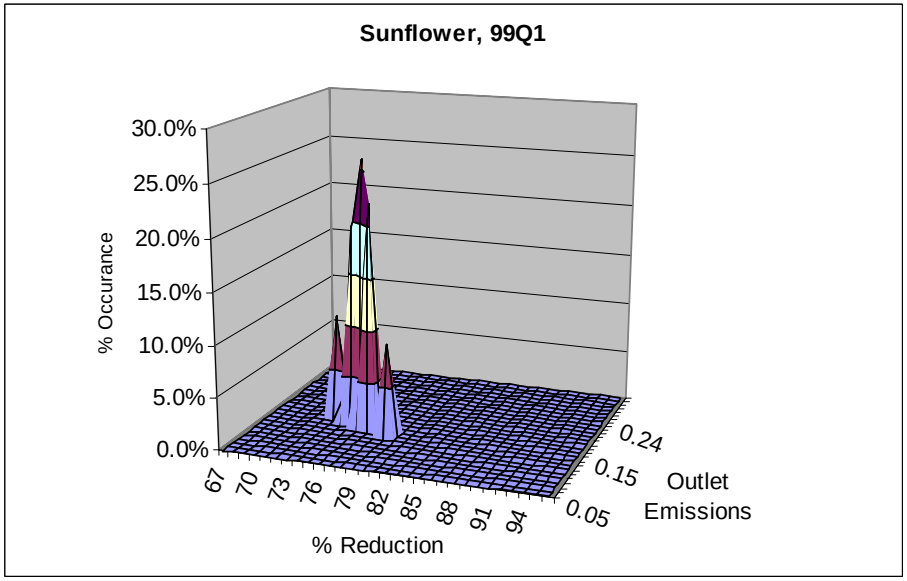
Outlet Emissions


Sunflower, 99Q1
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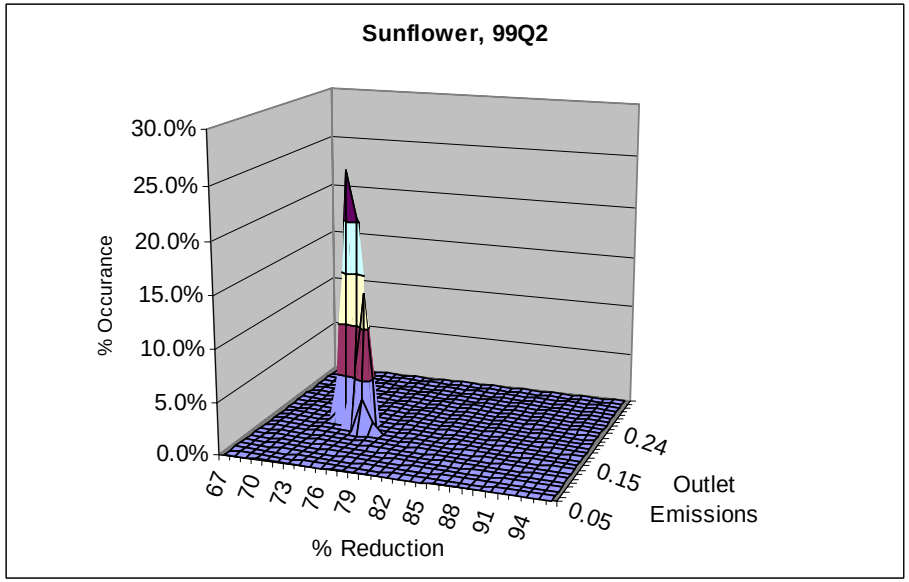
Emissions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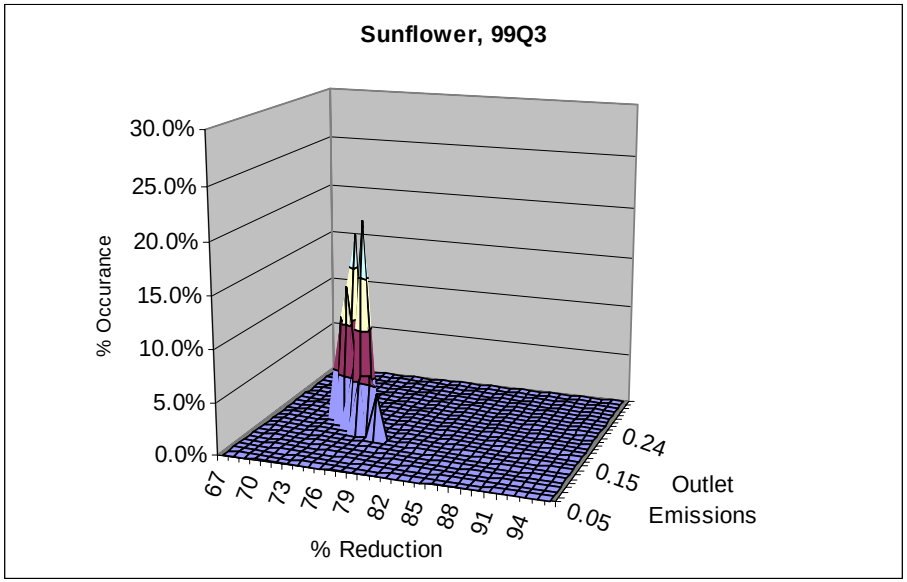
Emissions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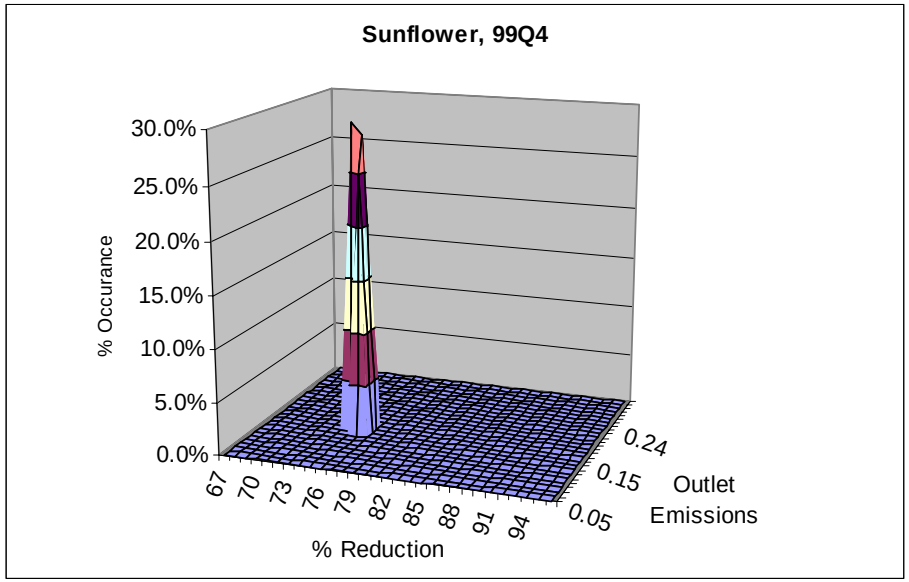
Sunflower, 99Q4
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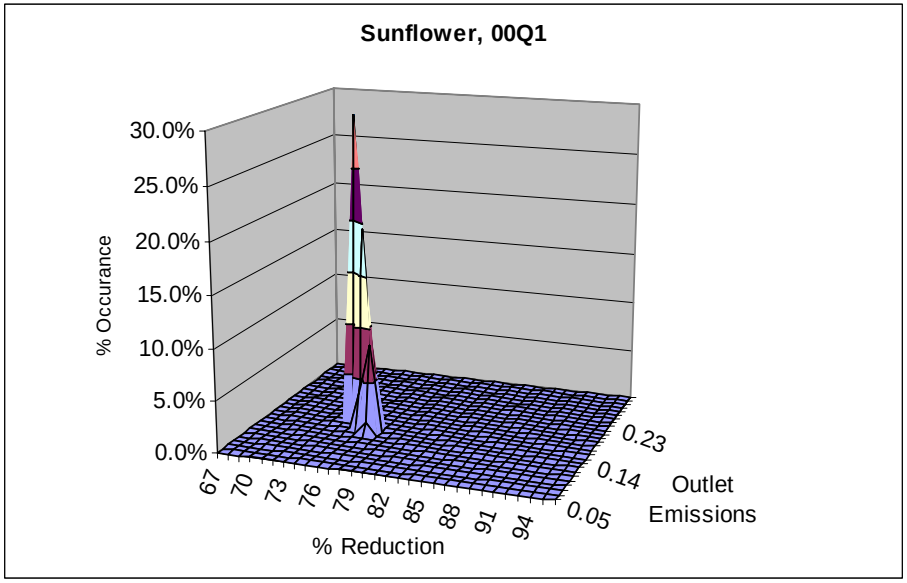
Sunflower, 00Q1
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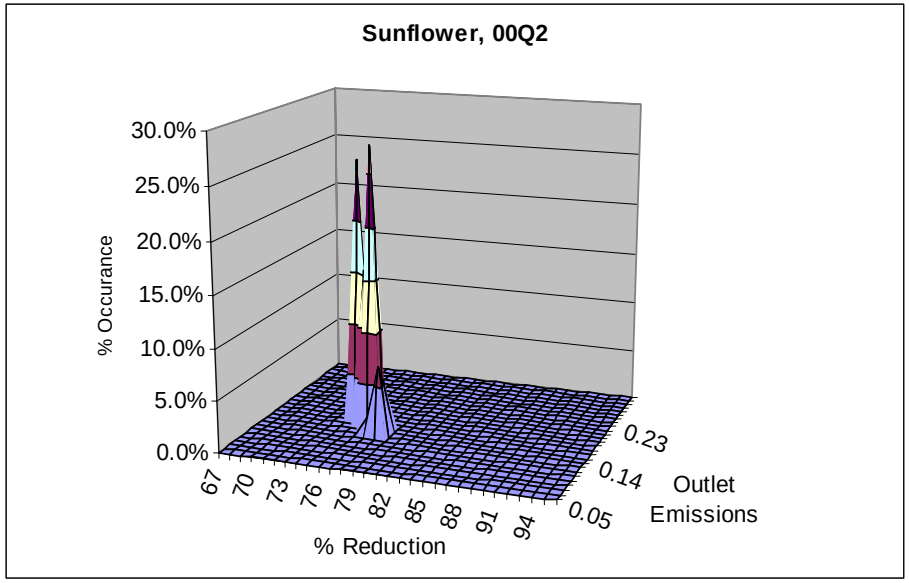
Sunflower, 00Q2
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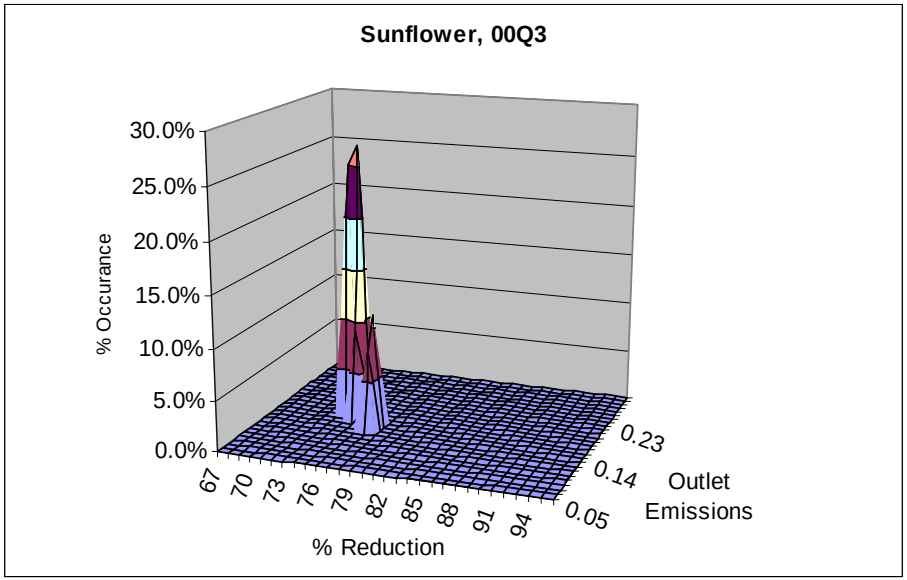
Emissions


Sunflower, 00Q3
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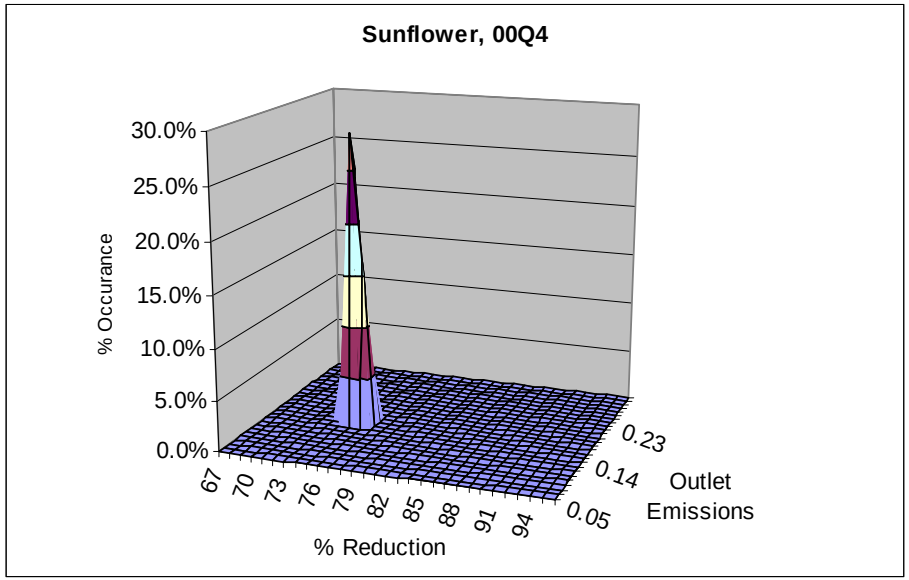
Sunflower, 00Q4
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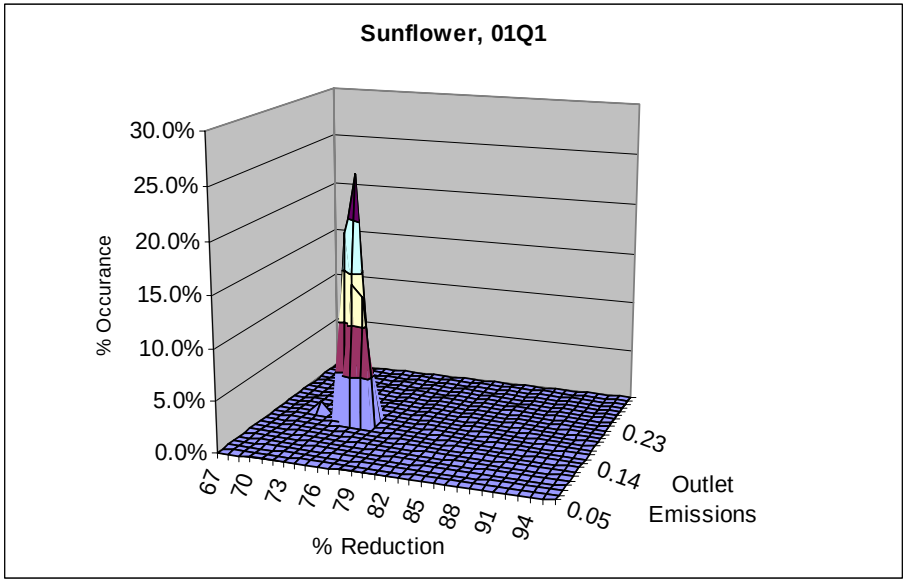
Emissions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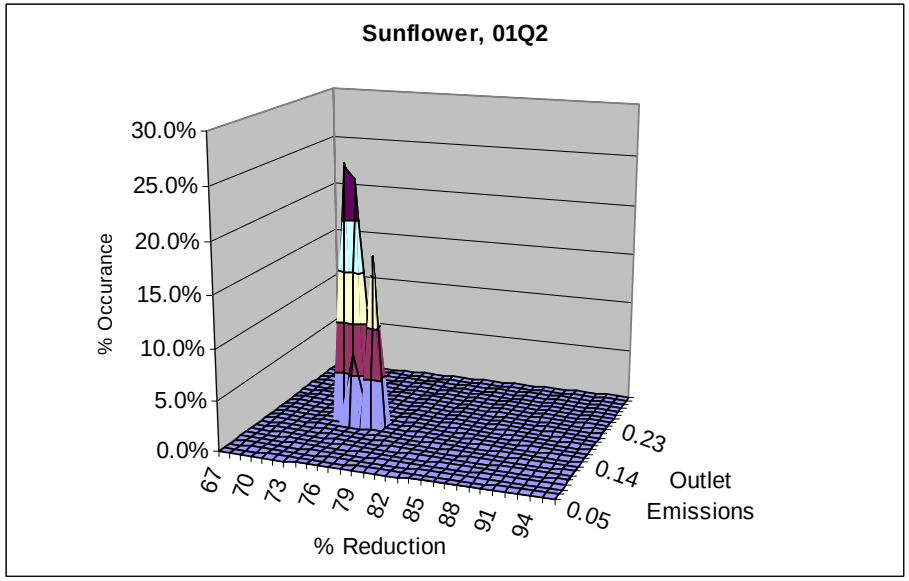
Emissions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% Occurance
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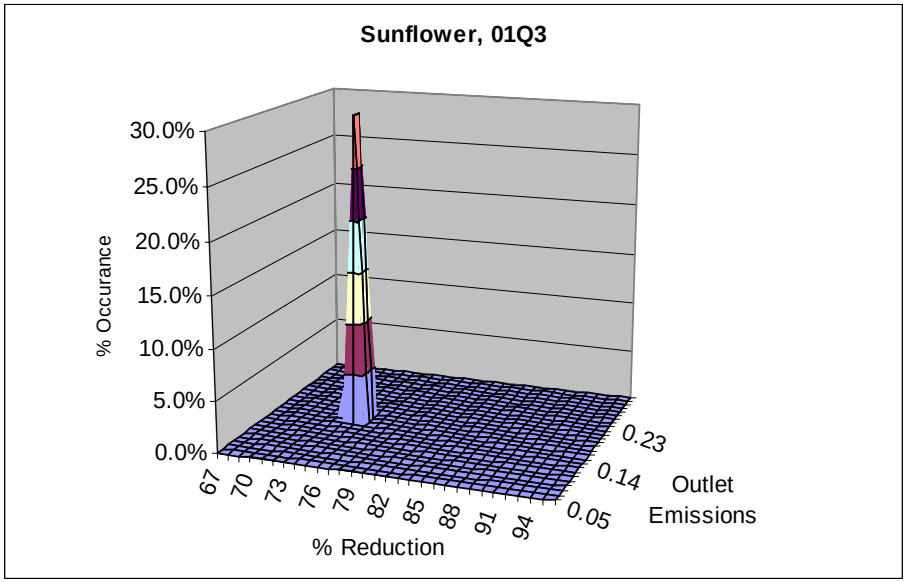
Outlet
Emissions


Sunflower, 01Q3
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% Occurance
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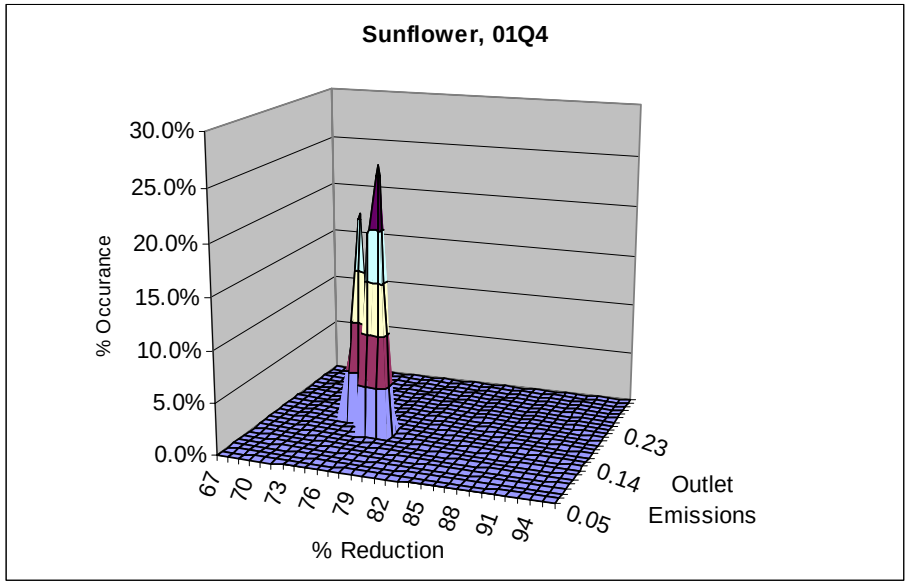
Outlet
Emissions


Sunflower, 01Q4
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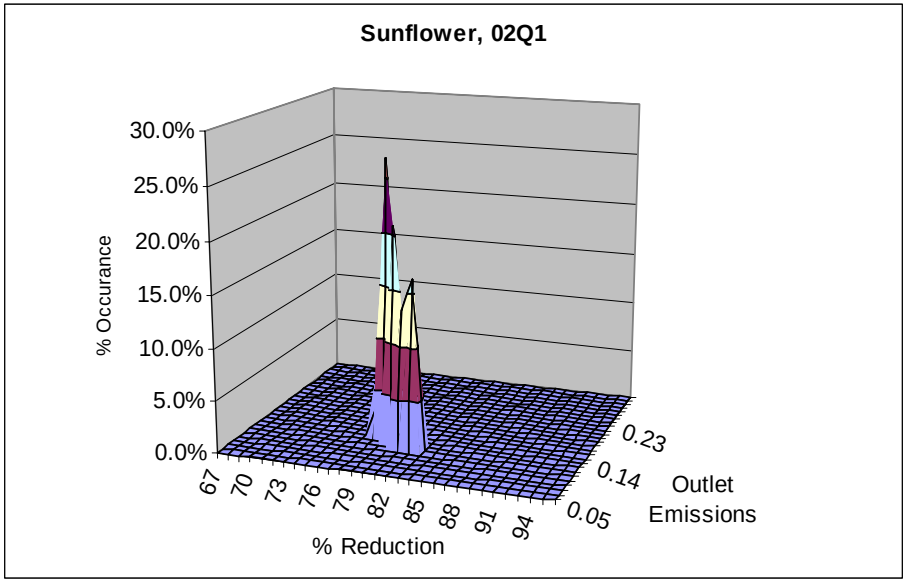
Emissions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% Reduction
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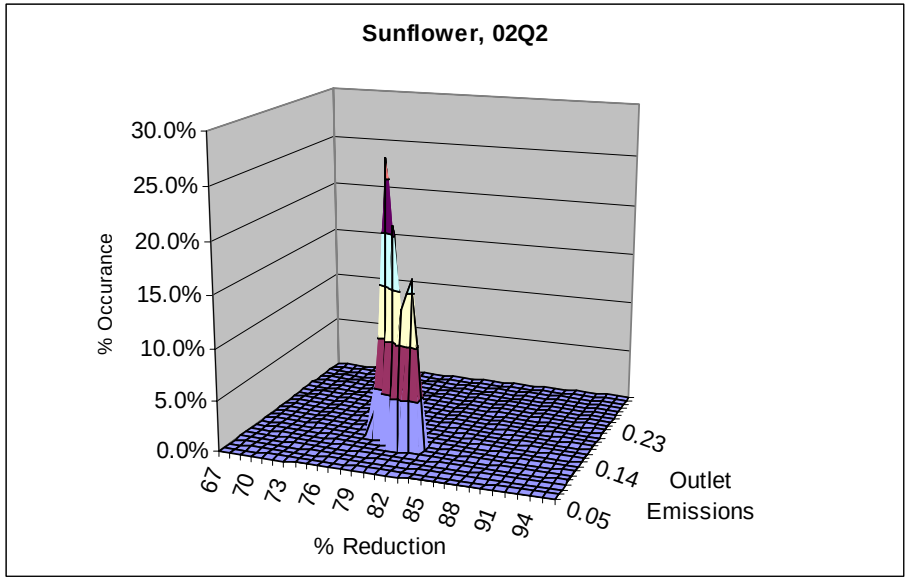
Outlet
Emissions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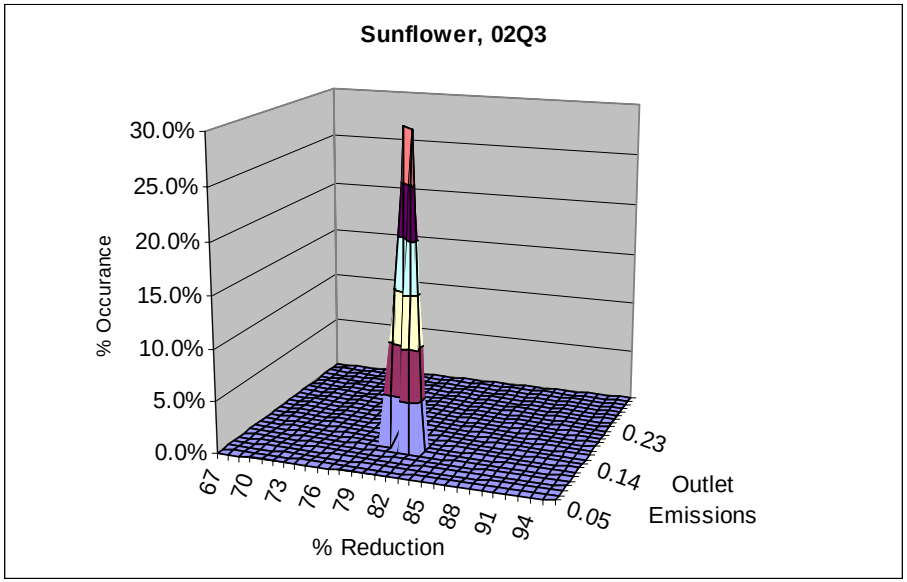
Outlet
Emissions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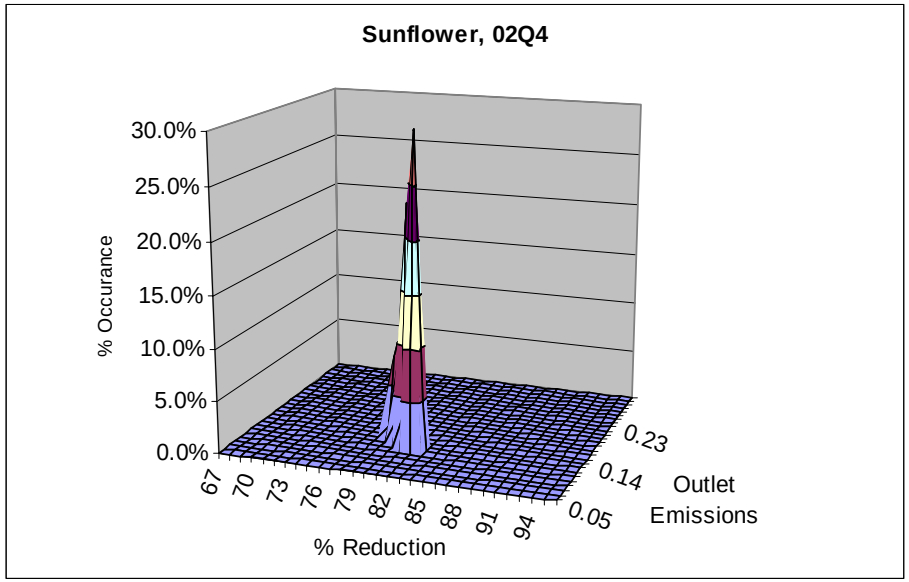
Emissions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% Occurance
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% Reduction
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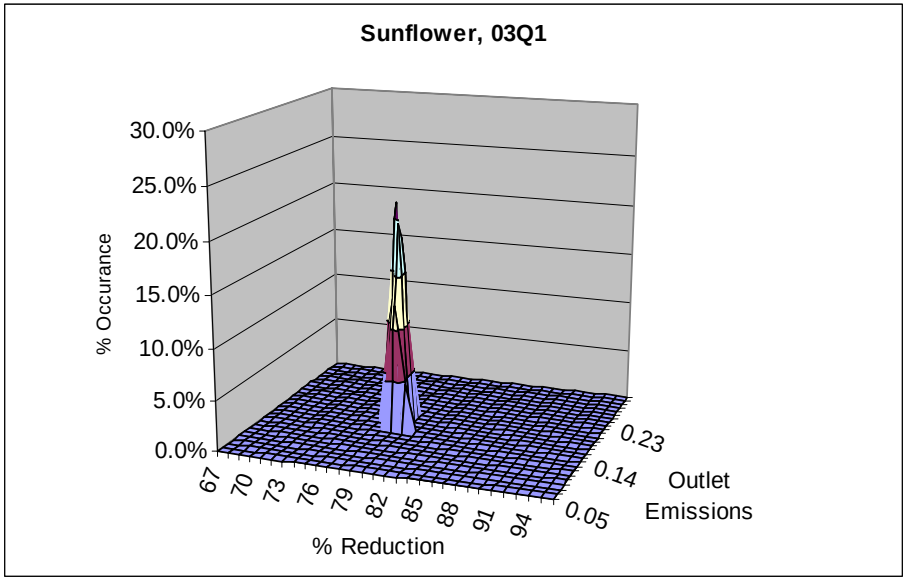
Outlet
Emissions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30.0%
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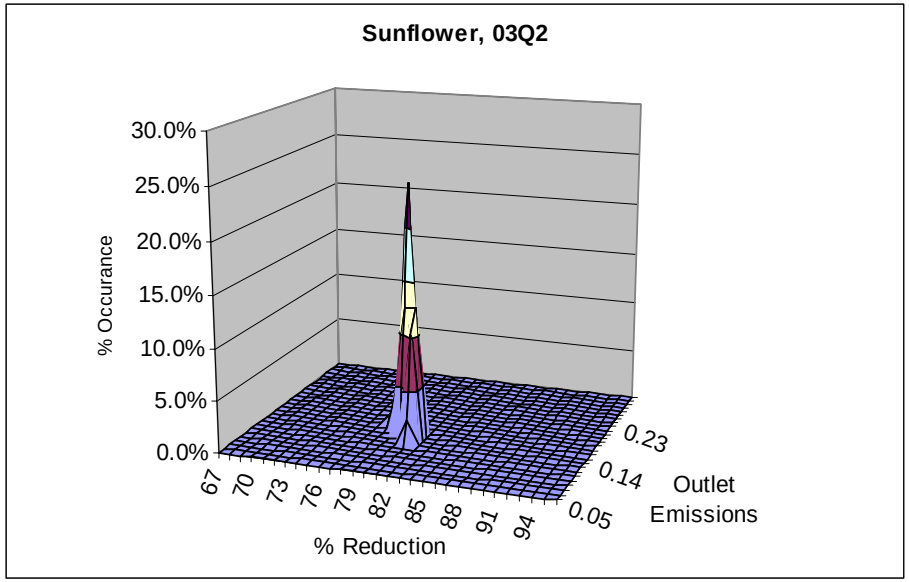
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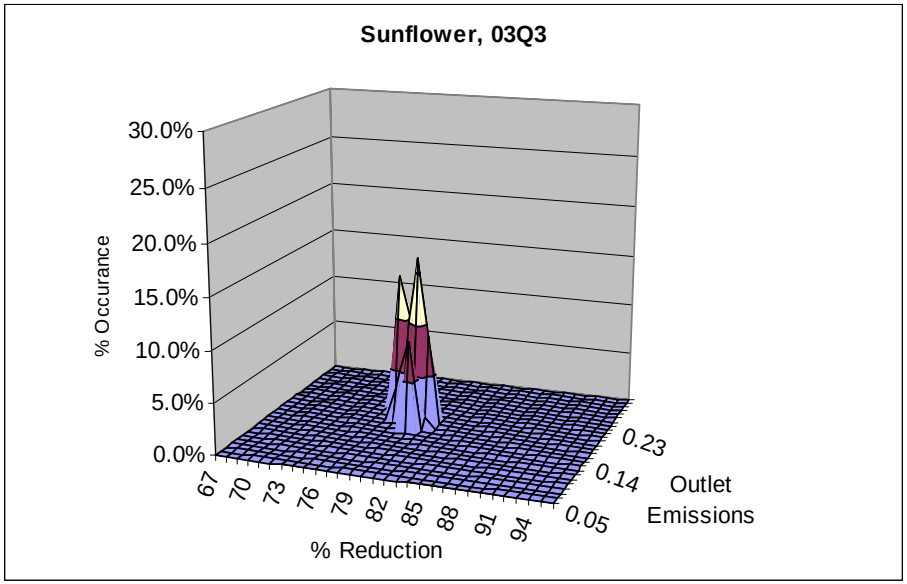
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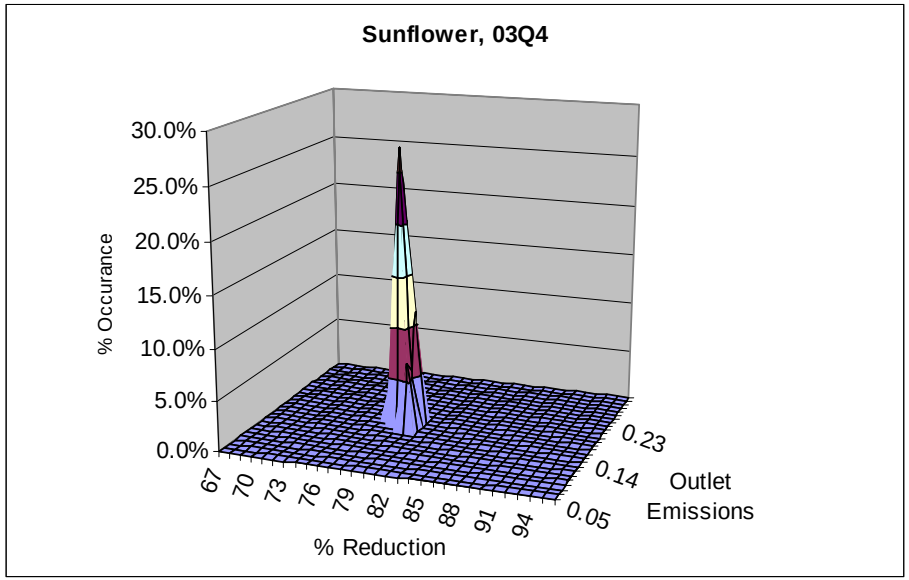
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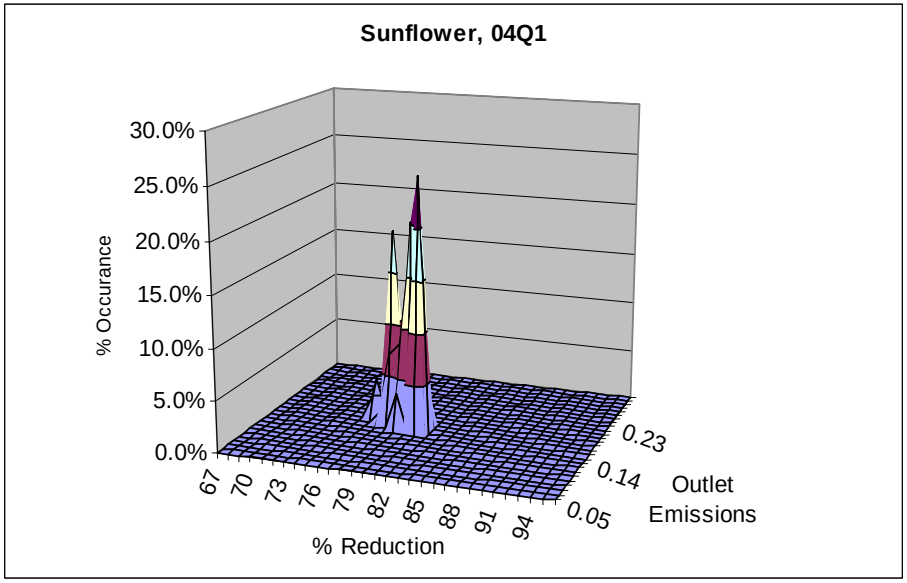
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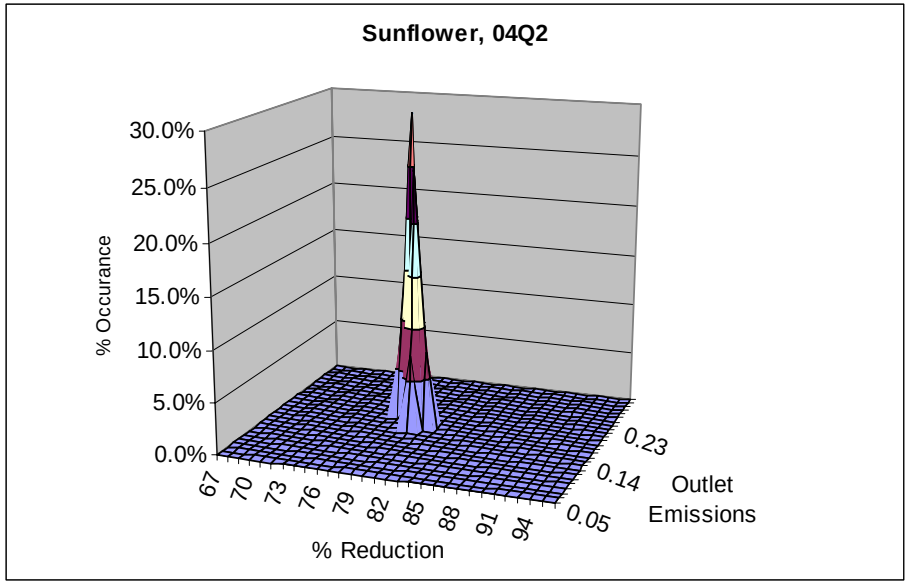
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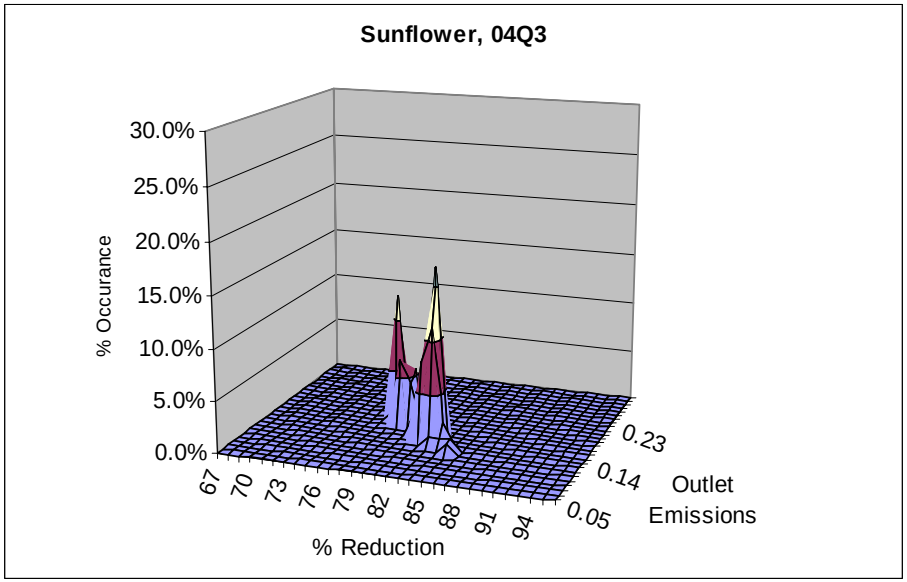
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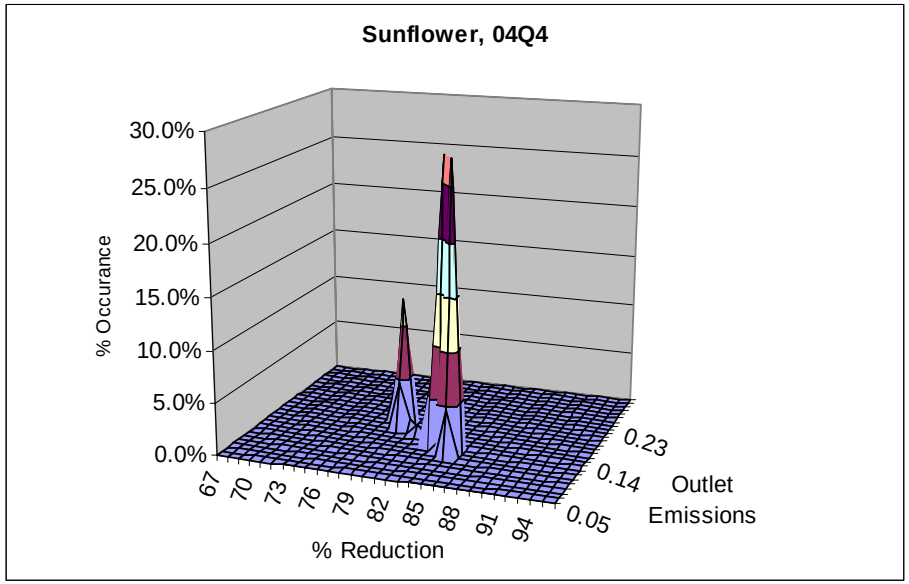
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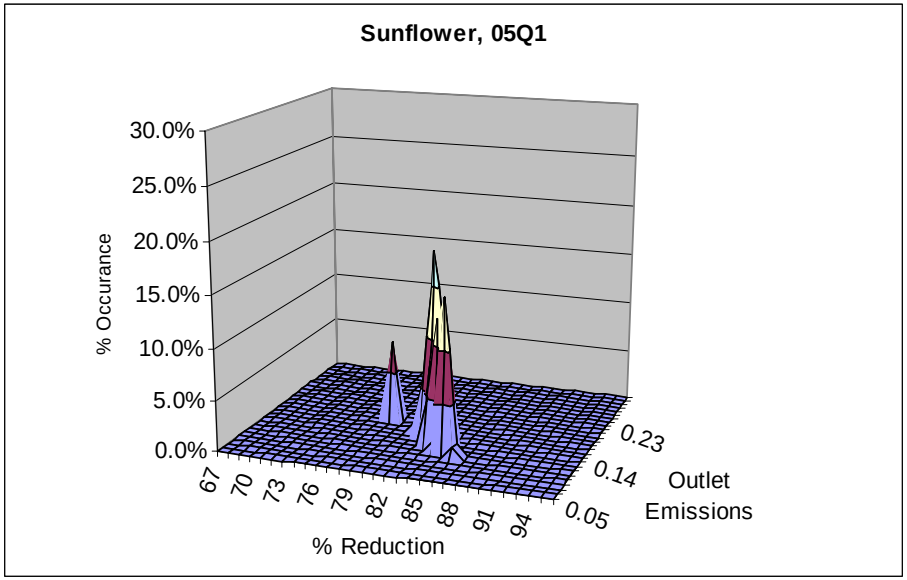
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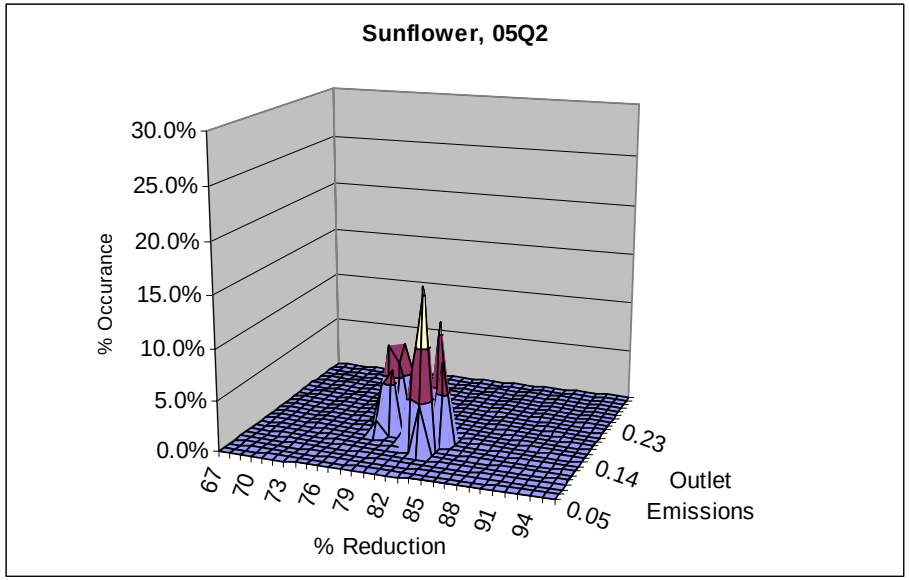
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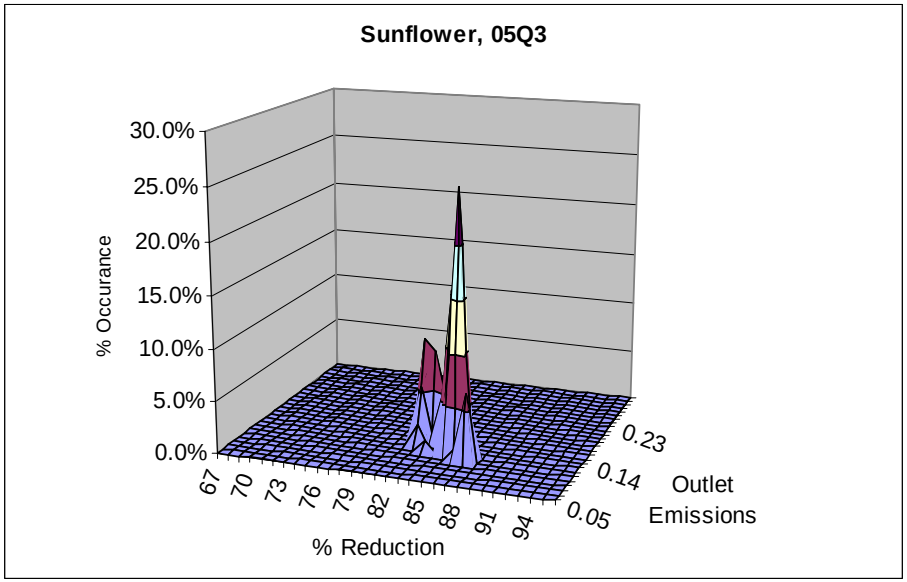
Sunflower, 05Q3
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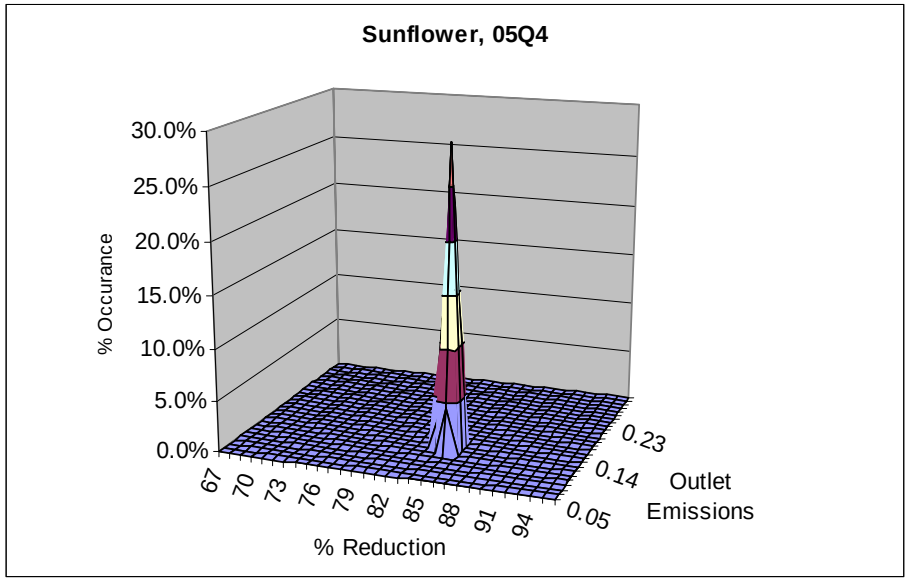
Sunflower, 05Q4
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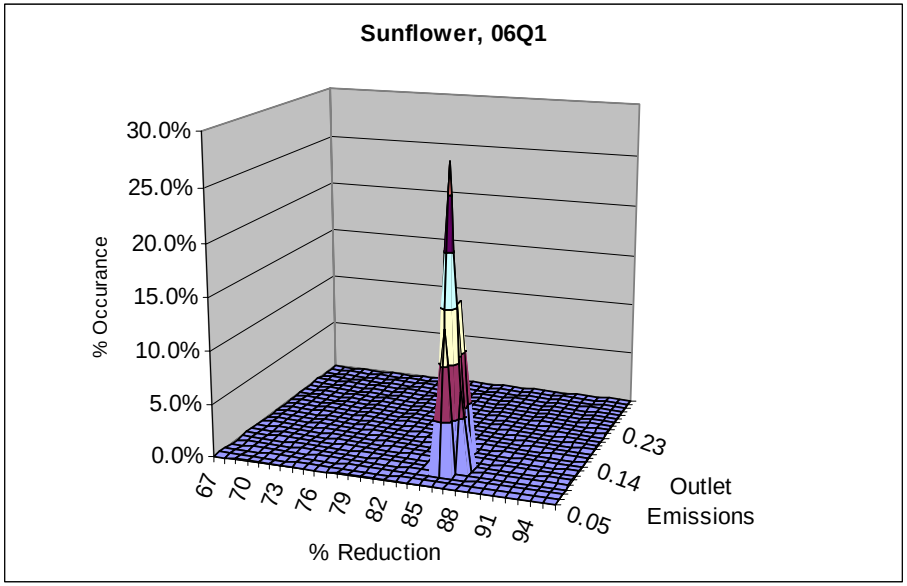
Emissions


Sunflower, 06Q1
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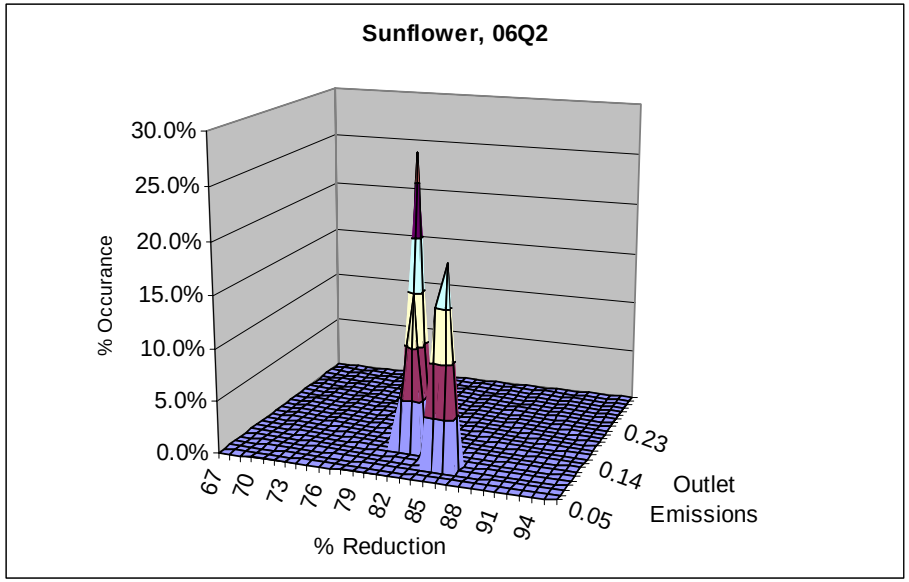
Sunflower, 06Q2
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Outlet
Emissions

**Attachment E**
**Burlington Northern "Guide to Coal Mines" Analysis**

"Guide to Coal Mines", Burlington Northern and Santa Fe Railway

http://www.bnsf.com/markets/coal/pdf/mineguide.pdf

| Coal Region | Mine | Sulfur, %wt | GHV, Btu/lb | #SO2/mmBtu | Permitted Annual Production, million tpy | Permit Weighted #SO2/mmBtu | Annual Production, million tpy (1996) | Production Weighted #SO2/mmBtu |
|---|---|---|---|---|---|---|---|---|
| PRB-Montana | Decker | 0.40 | 9,500 | 0.84 | 14 | | 11 | |
| PRB-Montana | Bull Mountain No. 1 | 0.50 | 10,450 | 0.96 | 6 | | 0.3 | |
| PRB-Montana | Absaloka | 0.65 | 8,750 | 1.49 | 7 | | 4.7 | |
| PRB-Montana | Rosebud | 0.80 | 8,750 | 1.83 | 18 | | 8 | |
| PRB-Montana | Big Sky | 0.95 | 8,800 | 2.16 | 5 | 1.41 | 5 | 1.43 |
| PRB-Wyoming | Rochelle | 0.21 | 8,750 | 0.48 | 30 | | 26.2 | |
| PRB-Wyoming | Antelope | 0.22 | 8,800 | 0.50 | 30 | | 12 | |
| PRB-Wyoming | North Rochelle | 0.23 | 8,800 | 0.52 | 15 | | Planned | |
| PRB-Wyoming | North Antelope | 0.24 | 8,800 | 0.55 | 35 | | 28.6 | |
| PRB-Wyoming | Black Thunder | 0.28 | 8,850 | 0.63 | 44 | | 39.2 | |
| PRB-Wyoming | Belle Ayr | 0.30 | 8,549 | 0.70 | 25 | | 20 | |
| PRB-Wyoming | Caballo Rojo | 0.32 | 8,450 | 0.76 | 30 | | 15.1 | |
| PRB-Wyoming | Coal Creek | 0.33 | 8,380 | 0.79 | 10 | | 5.8 | |
| PRB-Wyoming | Rawhide | 0.36 | 8,320 | 0.87 | 24 | | 15 | |
| PRB-Wyoming | Cordero | 0.37 | 8,350 | 0.89 | 24 | | 13 | |
| PRB-Wyoming | Caballo | 0.38 | 8,500 | 0.89 | 35 | | 22 | |
| PRB-Wyoming | Dry Fork | 0.37 | 8,175 | 0.91 | 15 | | 2.9 | |
| PRB-Wyoming | Buckskin | 0.40 | 8,450 | 0.95 | 20 | | 11.9 | |
| PRB-Wyoming | Eagle Butte | 0.41 | 8,350 | 0.98 | 20 | | 15.7 | |
| PRB-Wyoming | Jacobs Ranch | 0.45 | 8,695 | 1.04 | 35 | | 24.6 | |
| PRB-Wyoming | Wyodak Clovis Point | 0.42 | 8,050 | 1.04 | 10 | | 0.2 | |
| PRB-Wyoming | Fort Union | 0.42 | 7,990 | 1.05 | 8.2 | **0.76** | 1 | **0.74** |
| Colorado-NM | York Canon | 0.50 | 12,000 | 0.83 | 6 | | 1.3 | |
| Colorado-NM | Lorencito | 0.60 | 12,800 | 0.94 | 2.5 | | Planned | |
| Colorado-NM | King | 0.67 | 12,800 | 1.05 | 0.8 | | 0.3 | |
| Colorado-NM | McKinley | 0.54 | 9,907 | 1.09 | 9 | | 5.3 | |
| Colorado-NM | Lee Ranch | 0.78 | 9,150 | 1.70 | 6 | 1.13 | 4.3 | 1.27 |
| Illinois | Rend Lake | 1.10 | 12,100 | 1.82 | 3.5 | | 3.3 | |
| Illinois | Crown II | 3.35 | 10,700 | 6.26 | 2.5 | 3.54 | 1.7 | 3.21 |
| North Dakota | Freedom | 0.70 | 6,775 | 2.07 | | | 15.7 | |
| North Dakota | Beulah | 0.90 | 7,000 | 2.57 | 4.5 | 2.57 | 2.6 | 2.14 |
| Utah | Sufco | 0.35 | 11,450 | 0.61 | | | 4.2 | |
| Utah | Deer Creek | 0.41 | 11,615 | 0.71 | | | 4.3 | |
| Utah | Bear Canyon #1 | 0.50 | 12,400 | 0.81 | | | 0.6 | |
| Utah | Willow Creek | 0.50 | 11,950 | 0.84 | 5 | | | |
| Utah | Soldier Canyon | 0.50 | 11,800 | 0.85 | | | 1 | |
| Utah | Skyline | 0.50 | 11,750 | 0.85 | | | 4.4 | |
| Utah | Cyprus Plateau | 0.55 | 11,700 | 0.94 | 3 | | 3 | |
| Utah | Crandall Canyon | 0.60 | 12,300 | 0.98 | | | 2.5 | |
| Utah | Aberdeen | 0.60 | 12,000 | 1.00 | | 0.88 | 2.5 | 0.82 |
| Washington | John Henry | 0.80 | 11,800 | 1.36 | 0.33 | 1.36 | 0.19 | 1.36 |

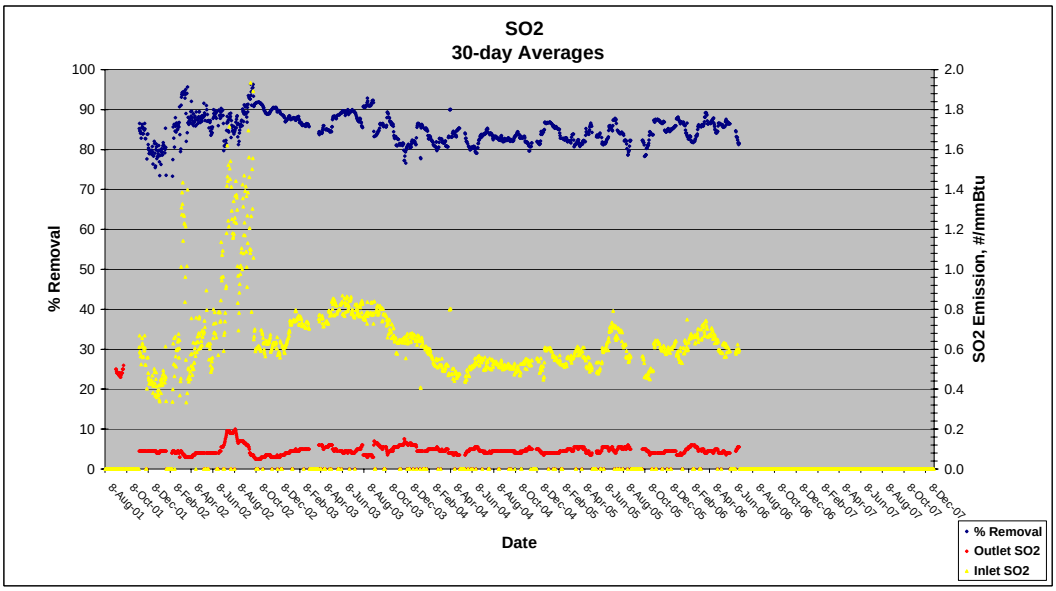
**Attachment F**
**Portions of KCPL – Hawthorn Scrubber Analysis**

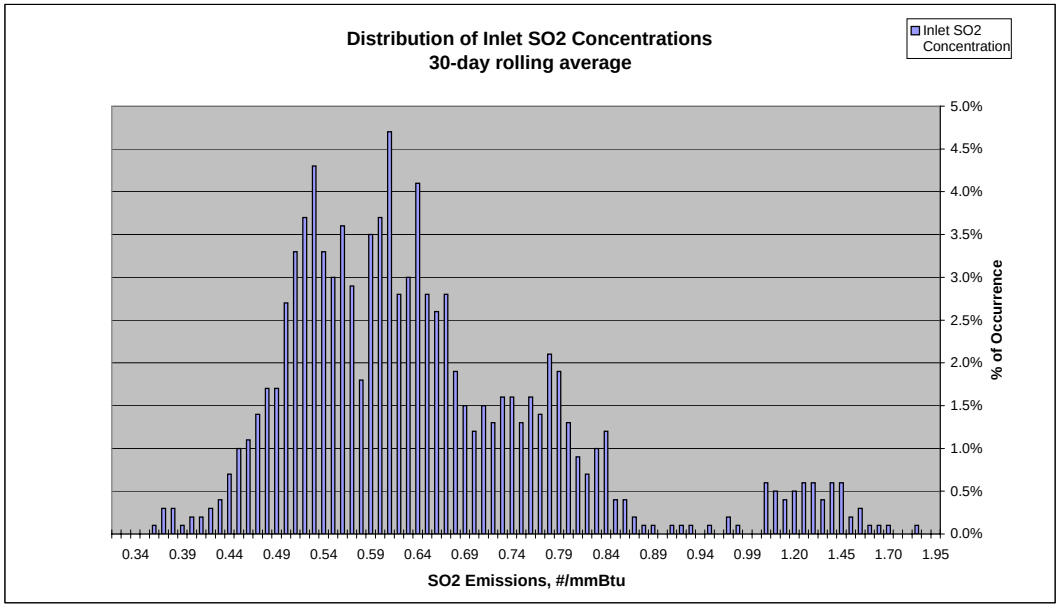
KCPL Hawthorn Unit 5A
SO2 Emissions Scrubber Performance

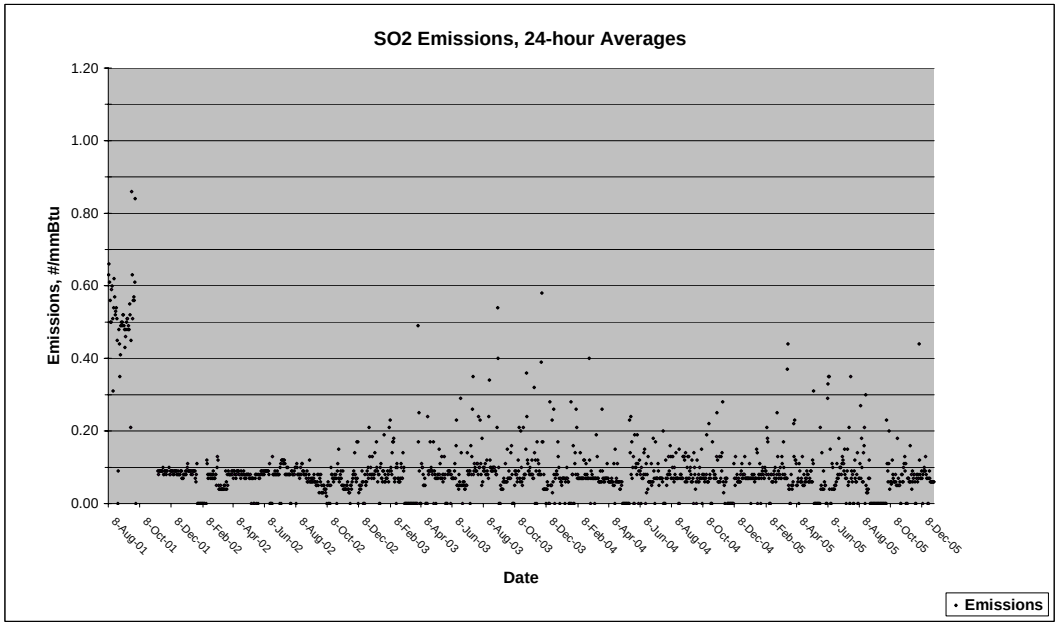
| Year | Quarter | SO2 Emissions, #/mmBtu | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 0.05 | 0.06 | 0.07 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 | 0.16 | 0.17 | 0.18 | 0.19 | 0.20 |
| 2001 | 1 | -- Not Yet Operating -- | | | | | | | | | | | | | | | |
| 2001 | 2 | -- Not Yet Operating -- | | | | | | | | | | | | | | | |
| 2001 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2001 | 4 | 0% | 0% | 0% | 2% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 1 | 0% | 18% | 25% | 53% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 2 | 0% | 14% | 23% | 94% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2002 | 3 | 0% | 0% | 10% | 14% | 14% | 15% | 24% | 35% | 45% | 64% | 67% | 69% | 71% | 84% | 99% | 100% |
| 2002 | 4 | 16% | 63% | 95% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 1 | 0% | 0% | 0% | 16% | 52% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 2 | 0% | 0% | 0% | 9% | 48% | 63% | 77% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 3 | 0% | 8% | 34% | 45% | 52% | 68% | 81% | 91% | 98% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2003 | 4 | 0% | 0% | 1% | 6% | 20% | 25% | 49% | 84% | 96% | 98% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 1 | 0% | 0% | 0% | 0% | 49% | 95% | 99% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 2 | 0% | 0% | 20% | 54% | 65% | 89% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 3 | 0% | 0% | 0% | 20% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2004 | 4 | 0% | 0% | 4% | 39% | 68% | 97% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 1 | 0% | 0% | 0% | 44% | 73% | 90% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 2 | 0% | 0% | 8% | 32% | 44% | 62% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 3 | 0% | 0% | 0% | 4% | 15% | 52% | 96% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2005 | 4 | 0% | 0% | 2% | 45% | 87% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2006 | 1 | 0% | 0% | 19% | 37% | 52% | 72% | 90% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2006 | 2 | 0% | 0% | 1% | 41% | 77% | 93% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| 2006 | 3 | | | | | | | | | | | | | | | | |
| 2006 | 4 | | | | | | | | | | | | | | | | |
| 2007 | 1 | | | | | | | | | | | | | | | | |
| 2007 | 2 | | | | | | | | | | | | | | | | |
| 2007 | 3 | | | | | | | | | | | | | | | | |
| 2007 | 4 | | | | | | | | | | | | | | | | |

| Year | Quarter | SO2 % Removal | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 73 | 74 | 75 | 76 | 77 | 78 | 79 | 80 | 81 | 82 | 83 | 84 | 85 | 86 | 87 | 88 | 89 | 90 | 91 | 92 | 93 | 94 | 95 | 96 |
| 2001 | 1 | -- Not Yet Operating -- | | | | | | | | | | | | | | | | | | | | | | | |
| 2001 | 2 | -- Not Yet Operating -- | | | | | | | | | | | | | | | | | | | | | | | |
| 2001 | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2001 | 4 | 100.0% | 100.0% | 100.0% | 97.9% | 93.6% | 93.6% | 87.2% | 72.4% | 57.5% | 46.8% | 44.7% | 38.3% | 25.5% | 8.5% | 4.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2002 | 1 | 100% | 97% | 96% | 96% | 94% | 92% | 88% | 78% | 67% | 58% | 56% | 54% | 50% | 44% | 36% | 29% | 25% | 24% | 24% | 21% | 21% | 18% | 4% | 1% |
| 2002 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 94% | 100% | 100% | 100% | 100% | 96% | 92% | 82% | 55% | 26% | 13% | 3% | 1% | 0% | 0% | 0% | 0% |
| 2002 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 99% | 93% | 90% | 89% | 84% | 74% | 63% | 52% | 40% | 30% | 24% | 16% | 16% | 9% | 6% | 3% |
| 2002 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 95% | 90% | 61% | 32% | 16% | 0% | 0% | 0% | 0% |
| 2003 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 66% | 48% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2003 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 87% | 65% | 60% | 60% | 43% | 13% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2003 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 97% | 90% | 83% | 70% | 59% | 51% | 44% | 34% | 11% | 1% | 0% | 0% | 0% |
| 2003 | 4 | 100% | 100% | 100% | 100% | 100% | 96% | 95% | 94% | 89% | 58% | 44% | 33% | 31% | 31% | 16% | 10% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 98% | 98% | 94% | 71% | 46% | 26% | 26% | 16% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 94% | 82% | 65% | 55% | 34% | 21% | 6% | 6% | 6% | 6% | 6% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 70% | 31% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2004 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 97% | 84% | 57% | 31% | 9% | 4% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 94% | 71% | 51% | 44% | 30% | 18% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 82% | 53% | 38% | 18% | 11% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 94% | 88% | 85% | 63% | 63% | 38% | 29% | 17% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2005 | 4 | 100% | 100% | 100% | 100% | 100% | 100% | 96% | 93% | 90% | 84% | 77% | 77% | 62% | 35% | 32% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2006 | 1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 89% | 72% | 65% | 62% | 34% | 18% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2006 | 2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 97% | 93% | 88% | 81% | 74% | 39% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2006 | 3 | | | | | | | | | | | | | | | | | | | | | | | | |
| 2006 | 4 | | | | | | | | | | | | | | | | | | | | | | | | |
| 2007 | 1 | | | | | | | | | | | | | | | | | | | | | | | | |
| 2007 | 2 | | | | | | | | | | | | | | | | | | | | | | | | |
| 2007 | 3 | | | | | | | | | | | | | | | | | | | | | | | | |
| 2007 | 4 | | | | | | | | | | | | | | | | | | | | | | | | |

**KCPL Hawthorn Unit 5A**



**Attachment G**
**Excerpt from City Utilities of Springfield**
**"BACT Emission Limitations for PC Boilers Firing Western Subbituminous Coal"**

**BACT Emission Limitations for PC Boilers Firing Western Subbituminous Coal**

**Sulfur Dioxide Emissions:**

The BACT analysis that City Utilities submitted to the Missouri DNR concluded that BACT for $SO_2$ at Southwest Unit 2 was 0.12 lbs/mmBtu on a 30-day rolling average basis. This conclusion was based on the proven control capabilities of dry FGD systems on PRB coal-fired units.

Subsequent to the submittal of the PSD permit application, MDNR has requested that City Utilities investigate the feasibility of achieving an $SO_2$ emission level of 0.10 lbs/mmBtu with a dry FGD system.

Evaluating the feasibility of achieving an $SO_2$ emission rate of 0.10 lbs/mmBtu for Southwest Unit 2 is a two step process. The first step is to consider the technical feasibility of meeting the 0.10 lb/mmBtu limit. If it is determined to be technically feasible, then environmental, energy and economic factors are considered.

Technical Feasibility

The technical feasibility evaluation must consider the potential fuels that may be fired at Southwest Unit 2. CU is planning on firing PRB coals in the unit which inherently have low sulfur content. As part of the original BACT analysis, potential sources of the PRB-coal were evaluated. This evaluation determined that fuel for Southwest Unit 2 may have sulfur content up to 0.60 percent with a higher heating value of 8200 Btu/lb. This corresponds to maximum uncontrolled emissions of 1.462 lbs of SO2/mmBtu. The original fuel analysis for Southwest Unit 2 remains valid and is the basis for evaluating achieving an emission rate of 0.10 lbs/mmBtu for the unit.

The next area to consider when evaluating the feasibility of achieving SO2 emissions of 0.10 lbs/mmBtu is the removal capabilities of dry FGD. Virtually all dry FGD systems installed on units over 100 MW are spray dryers. Spray dryers include either rotary atomizers or dual fluid nozzles to atomize the lime slurry to achieve good gas-to-liquid contact.

Good gas-to-liquid contact is essential to obtain high control efficiencies. The maximum control efficiency that has been guaranteed for a spray dryer/fabric filter FGD system installed on a coal-fired utility boiler is 94 percent (Hawthorn 5 – 94%, Council Bluffs 4 – 93.6%). These are very large units that require multiple absorber modules. Having multiple absorber modules provides an additional level of redundancy which is not practical for smaller units such as Southwest Unit 2.

Obtaining this high removal efficiency is dependent not only on good gas-to-liquid contact, but, also on how closely the absorber outlet temperature approaches the adiabatic saturation temperature. Operating closer to the adiabatic saturation temperature allows higher $SO_2$ control efficiencies.

There are process limitations on how close a spray dryer can be operated to the adiabatic saturation temperature. If the outlet temperature from a spray dryer is too close to the saturation temperature, a number of operating problems will occur. These include build-up in the absorber modules, blinding of fabric filter bags, corrosion in the fabric filter and ductwork, and operating and maintenance problems with the fly ash handling system.

The limit on how close a spray dryer outlet temperature can safely approach the adiabatic saturation temperature is around 25 degrees F. Operating at closer approach temperatures results in severe operating problems. Most spray dryers are operated with outlet temperatures 30-40 degrees above the saturation temperatures. Even at these higher operating temperatures, absorber build-up, corrosion of the fabric filter and ductwork and fly ash handling issues have been common problems for dry FGD systems.

Continuously maintaining 94 percent control on a unit with a dry FGD would be difficult, if not impossible, to accomplish and has not been demonstrated on any existing unit. Achieving 94 percent control requires a well designed absorber that has good liquid-to-gas contact and the ability to continuously operate at an approach temperature 25 degrees F above saturation. There are no utility units with spray dryers that continually operate at control efficiencies approaching 94 percent. There are a very few facilities that have been continuously able to achieve a $SO_2$ control efficiency of 90 percent.

The large majority of coal-fired utility installations have used rotary atomizers. Installations with rotary atomizers have been more successful in achieving high removal efficiencies than units with dual fluid nozzles. Atomizers (rotary and dual fluid nozzle) are high maintenance pieces of equipment, that are subject to severe erosion and pluggage conditions. Periodically, the atomizers must be changed out for inspection and cleaning. During change out of the atomizers, $SO_2$ emissions from the unit will be higher.

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 common to change rotary atomizers out at monthly intervals. Dual fluid nozzles are likely to require more frequent change out. In addition to normal atomizer maintenance, it is relatively common for emergency conditions to occur at spray dryer facilities that require the immediate change out of atomizers.

According to manufacturers, a planned change-out of an atomizer should take 2 to 3 hours to complete. Change out of an atomizer under emergency conditions will likely take longer. Typically, a spray dryer may be out of service 2 to 3 hours per month to allow for scheduled atomizer maintenance. However, it is fairly common for a spray dryer to be out of service for additional hours in a month due to unanticipated equipment problems and maintenance.

Establishing a permitted emission rate for a unit needs to take into account the maximum sulfur fuel that can be fired and the impact of normal and common maintenance

activities. Several scenarios were developed to evaluate the impact of spray dryer operating conditions that may be reasonably expected to occur in the course of a year.

The first scenario evaluated assumed an accumulation of 10-hours of spray dryer outage during a 30-day averaging period. During the remainder of the month, the spray dryer was assumed to operate at the maximum achievable control efficiency for a spray dryer of 94 percent. This scenario is summarized in Table No. 1:

Table No. 1

| Hours of Operation | SO2 Emission Rate (lbs/mmBtu) |
|---|---|
| 710 | 0.088 |
| 10 | 1.462 |
| | |
| **30-Day Average** | 0.107 |

Table No. 2 illustrates the emissions that would result during a 30-day period from a scenario if only one scheduled atomizer change out is required and during the remainder of the month a control efficiency of 94 percent is maintained.

Table No. 2

| Hours of Operation | SO2 Emission Rate (lbs/mmBtu) |
|---|---|
| 717 | 0.088 |
| 3 | 1.462 |
| | |
| **30-Day Average** | **0.094** |

The scenarios provided in Tables 1 and 2 assume that a $SO_2$ removal efficiency of 94 percent can be continuously maintained when the spray dryer is in service. This is not a technically feasible assumption. A 94 percent control level is the best that can be accomplished with a spray dryer/fabric filter system. It requires that the absorber outlet temperature be maintained within 25 degrees of the adiabatic saturation temperature. Continuous operation at this temperature can result in severe operating problems and reduced control equipment reliability. Unexpected operating conditions will occur to prevent peak removal efficiency.

In order to further evaluate the control capabilities of operating spray dryer/ fabric filter systems, 2003 CEMS data were reviewed from a number of units that were designed to achieve $SO_2$ control levels above 90 percent. This review of CEMS data revealed that the highest continuous $SO_2$ control level maintained on any of the units was approximately 90 percent (Tri-States Craig 3, Platte River Rawhide). A continuous control level of slightly under 90 percent has been maintained on Hawthorn 5.

Table No. 3 provides projected emissions for a 30-day period with only a normal, scheduled atomizer change out and maintaining 90 percent control efficiency during the remainder of the month.

Table No. 3

| Hours of Operation | $SO_2$ Emission Rate (lbs/mmBtu) |
|---|---|
| 717 | 0.146 |
| 3 | 1.462 |
| | |
| **30-Day Average** | **0.151** |

Although the highest demonstrated continuous $SO_2$ control level achieved by units with spray dryers/fabric filters is approximately 90 percent, we believe that with proper design operation and maintenance, somewhat higher levels of control can be maintained. Table No. 4 provides projected monthly emissions with only one scheduled, normal atomizer change out and 92 percent control for the remainder of the period.

Table No. 4

| Hours of Operation | $SO_2$ Emission Rate (lbs/mmBtu) |
|---|---|
| 717 | 0.117 |
| 3 | 1.462 |
| | |
| **30-Day Average** | **0.123** |

Table No. 5 provides a summary of the spray dryer operating scenarios.

Table No. 5

| Scenario | Operating Removal Efficiency (%) | Spray Dryer Outage Hrs./Month | 30-Day Average Emissions (lbs/mmBtu) |
|---|---|---|---|
| 1 | 94 | 10 | 0.107 |
| 2 | 94 | 3 | 0.094 |
| 3 | 90 | 3 | 0.151 |
| 4 | 92 | 3 | 0.123 |

The above scenarios illustrate that it is unlikely that a 30-day rolling $SO_2$ average of 0.10 lbs/mmBtu could be achieved at Southwest Unit 2. A 3-hour spray dryer outage during a month adds over 0.006 lbs/mmBtu to the 30-day rolling average emissions. Achieving an emission rate of 0.10 lbs/mmBtu requires 94 percent control and monthly spray dryer outages limited to one 3-hour period for normal, scheduled atomizer maintenance. Even achieving an emission rate of 0.12 lbs/mmBtu requires the control efficiency to be maintained above 92 percent and the atomizer change outs limited to one per 30-day period.

Conclusions

Southwest Unit 2 is projected to have a service life of over 30-years. During this life span the unit must be continuously operated within the emission limits required by the operating permit. The permit limit established by BACT must not be lower than is technically feasible for the control method.

In the above analysis, consideration has been given to the technical feasibility of maintaining a $SO_2$ emission rate of 0.10 lbs/mmBtu with a spray dryer/fabric filter system on Southwest Unit 2. Achieving an emission rate of 0.10 lbs/mmBtu on a 30-day rolling average basis requires continual operation at a 94 percent control level with only one atomizer change out during a 30-day averaging period. This scenario is not technically feasible for Southwest Unit 2.

**Attachment H**
**Excerpts from**
**Draft PSD permit for Longleaf Energy Associates, LLC**
**C/o LS Power Development, LLC**
**http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/index.htm**

**Conclusions for $SO_2$**

[ Excerpted from Georgia DNR "Preliminary Determination" for LS Power Longleaf Energy draft PSD permit. ]

The Division has determined that the proposal to use a dry scrubber in combination with burning of low sulfur PRB coal to meet the requirements of BACT is acceptable. The Division has determined that the proposed $SO_2$ BACT emission limit of 0.12 lb/mmBtu is not acceptable. The Division has reviewed a permit for Newmont Nevada Energy Investments, LLC which details an innovative two-tiered $SO_2$ BACT limit. This two-tiered limit has different limits based on the sulfur content of the coal. If Longleaf accepts this two-tiered $SO_2$ limit it would be the third most stringent $SO_2$ emission limit for Pulverized Coal Boilers burning low sulfur western or PRB Coal. The Division proposed this two tiered limit to Longleaf in a letter dated February 23, 2006 requesting that Longleaf examine this approach and develop a similar tiered limit for the facility. Longleaf responded in a letter dated February 23, 2006 with the following three tiered $SO_2$ BACT limit.

- For uncontrolled $SO_2$ emissions less than or equal to 1.0 lb/mmBtu, the PC-fired boilers will not exceed 0.065 lb/mmBtu (30-day rolling average)
- For uncontrolled $SO_2$ emissions greater than 1.0 but less than 1.25 lb/mmBtu, the PC-fired boilers will not exceed 0.08 lb/mmBtu (30-day rolling average)
- For uncontrolled $SO_2$ emissions greater than 1.25 but less than 1.6 lb/mmBtu, the PC-fired boilers will not exceed 0.105 lb/mmBtu (30-day rolling average)
- The PC-fired boilers will not exceed 0.12 lb/mmBtu on a 24-hour average.
- The scrubbers will maintain 93.5% removal of $SO_2$.

The $SO_2$ BACT emission limit is set as stated above. The Division believes that this determination is consistent with recent BACT determinations.

**Condition 2. Allowable Emissions**

[ Excerpted from Georgia DNR "Draft Permit" for LS Power Longleaf Energy project ]

2.14 The Permittee shall not discharge, or cause the discharge, into the atmosphere, from each PC-Fired Boiler, S01 and S02, any gases which

d. Contain sulfur dioxide in excess of 0.065 lb/mmBtu on a 30-day rolling average when the uncontrolled sulfur dioxide emission rate is less than or equal to 1 lb/mmBtu on a 30-day rolling average. [40 CFR 52.21(j); 40 CFR 60.43a(i) (subsumed); 391-3-1-.02(2)(d) (subsumed)]

e. Contain sulfur dioxide in excess of 0.08 lb/mmBtu on a 30-day rolling average when the uncontrolled sulfur dioxide emission rate is greater than 1 lb/mmBtu but less than 1.25 lb/mmBtu on a 30-day rolling average. [40 CFR 52.21(j); 40 CFR 60.43a(i) (subsumed); 391-3-1-.02(2)(d) (subsumed)]

f. Contain sulfur dioxide in excess of 0.105 lb/mmBtu on a 30-day rolling average when the uncontrolled sulfur dioxide emission rate is greater than 1.25 lb/mmBtu but less than 1.6 lb//mmBtu on a 30-day rolling average. [40 CFR 52.21(j); 40 CFR 60.43a(i)

(subsumed); 391-3-1-.02(2)(d) (subsumed)]
g. Contain sulfur dioxide in excess of 0.12 lb/mmBtu on a 24-hour average. [40 CFR 52.21(j); 40 CFR 60.43a(i) (subsumed); 391-3-1-.02(2)(d) (subsumed)]

**Missouri Department of Natural Resources**
Air Pollution Control Program

# PART 70
# PERMIT TO OPERATE

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

**Operating Permit Number:** **OP2006-063**
**Expiration Date:** AUG 3 0 2011
**Installation ID:** 095-0031
**Project Number:** 2003-09-030

**Installation Name and Address**
Aquila – Sibley Generating Station
33200 E. Johnson Road
Sibley, MO 64088
Jackson County

**Parent Company's Name and Address**
Aquila, Inc.
PO Box 11739
Kansas City, MO 64138

**Installation Description:**
Aquila - Sibley Generating Station is an electric energy generating station located in Sibley, Missouri. Equipment at the installation includes three coal-fired and tire-derived fuel-fired boilers, coal and fly ash handling equipment, parts washer, welding equipment, storage tanks, and miscellaneous combustion equipment.

The installation is an existing major source of particulate matter less than ten microns ($PM_{10}$), sulfur oxides ($SO_X$), nitrogen oxides ($NO_X$), volatile organic compounds (VOC), carbon monoxide (CO) and hazardous air pollutants (HAP).

AUG 3 1 2006
Effective Date

Director or Designee
Department of Natural Resources

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# I. Installation Description and Equipment Listing

## INSTALLATION DESCRIPTION

Aquila - Sibley Generating Station is an electric energy generating station located in Sibley, Missouri. Equipment at the installation includes three coal-fired and tire-derived fuel-fired boilers, coal and fly ash handling equipment, parts washer, welding equipment, storage tanks, and miscellaneous combustion equipment.

The installation is an existing major source of particulate matter less than ten microns ($PM_{10}$), sulfur oxides ($SO_X$), nitrogen oxides ($NO_X$, volatile organic compounds (VOC), carbon monoxide (CO) and hazardous air pollutants (HAP).

| Reported Air Pollutant Emissions, tons per year | | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | Particulate Matter ≤ Ten Microns (PM-10) | Sulfur Oxides ($SO_X$) | Nitrogen Oxides ($NO_X$) | Volatile Organic Compounds (VOC) | Carbon Monoxide (CO) | Lead (Pb) | Hazardous Air Pollutants (HAPs) |
| 2004 | 38.52 | 12858.80 | 10127.41 | 89.71 | 407.99 | - | 112.00 |
| 2003 | 38.60 | 12511.50 | 12604.58 | 94.10 | 427.88 | - | 108.59 |
| 2002 | 37.40 | 11804.20 | 12326.16 | 89.21 | 405.59 | - | 100.44 |
| 2001 | 34.30 | 10530.30 | 13039.29 | 85.77 | 390.09 | - | 102.50 |
| 2000 | 38.90 | 15879.00 | 13542.21 | 92.16 | 376.07 | - | 85.95 |

## EMISSION UNITS WITH LIMITATIONS

The following list provides a description of the equipment at this installation which emits air pollutants and which is identified as having unit-specific emission limitations.

| Emission Unit # | Description of Emission Unit | 2004 EIQ EP# |
|---|---|---|
| EU0010 | Coal Conveyor #18 | EP-03 |
| EU0020 | Coal Handling System (Except for Conveyor #18) | EP-03 |
| EU0030 | Coal Crusher House | EP-04 |
| EU0040 | Fly Ash Handling System | EP-06 |
| EU0050 | Boiler #1 | EP-05A |
| EU0060 | Boiler #2 | EP-05B |
| EU0070 | Boiler #3 | EP-05C |
| EU0080 | Emergency Generator | EP-07 |
| EU0090 | Welding Machine | EP-08 |
| EU0100 | Welding Machine | EP-09 |
| EU0110 | Back-up Diesel Fire Pump | EP-11 |
| EU0120 | Parts Washer | EP-10 |
| EU0130 | Spray Paint Booth | EP-12 |

## EMISSION UNITS WITHOUT LIMITATIONS

The following list provides a description of the equipment that does not have unit specific limitations at the time of permit issuance.

Description of Emission Source

Coal unloading (EP-01)
Coal storage pile (EP-02)
Portable space heaters (EP-17)
Storage tanks for volatile organic liquids
- 20,000-gallon coal yard diesel tank, installed prior to 1984 (EP-15)
- 13,000 MgO/diesel tank, empty and out of service
- 8,500-gallon waste oil tank (EP-16)
- Two 1,000-gallon unleaded gasoline tanks
- 1,200-gallon emergency generator diesel tank
- Two 500-gallon MgO/diesel day tanks, empty and out of service
- 500-gallon steam jenny #1 fuel oil tank
- 500-gallon MgO flush tank, empty and out of service
- One 300-gallon fire water diesel tank
- Various tanks and drums for storing bearing oil, compressor fluid, diesel fuel supplement, hydraulic fluid, lube oil, mineral oil, silicon oil, solvent, transformer oil, turbine oil, and waste oil; none are over 40,000 gallons; and none have capacities of at least 75 $m^3$ and were constructed after July 23, 1984.

## DOCUMENTS INCORPORATED BY REFERENCE

These documents have been incorporated by reference into this permit.

1) Construction Permit #0393-004
2) Construction Permit #0897-025

# II. Plant Wide Emission Limitations

The installation shall comply with each of the following emission limitations. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued.

None

# III. Emission Unit Specific Emission Limitations

The installation shall comply with each of the following emission limitations. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued.

| IV. EU0010 – COAL CONVEYOR #18 | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0010 | Conveyor #18 conveys coal from storage pile, and transfers coal to conveyor #7 in transfer house #2. The coal is then transferred to crusher. Its MHDR 700 ton/hr; and it was installed in 1993 | NA. | EP-03 |

**PERMIT CONDITION EU0010-001**
10 CSR 10-6.070 New Source Performance Regulations and
40 CFR 60 Subpart Y Standards of Performance for Coal Preparation Plants

***Emission Limitation:***
The permittee shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

***Monitoring:***
1) The permittee shall conduct opacity readings on this emission unit (EU0010) using the procedures contained in USEPA Test Method 22. At a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by background contrast, ambient lighting, observer position relative to lighting, wind and the presence of uncombined water. Readings are only required when the emission unit is operating and when the weather conditions allow. If no visible or other significant emissions are observed using these procedures, then no further observations would be required. For emission units with visible emissions perceived or believed to exceed the applicable opacity standard, the source representative would then conduct a Method 9 observation.
2) The following monitoring schedule must be maintained:
   a) Weekly observations shall be conducted for a minimum of eight consecutive weeks after permit issuance. Should no violation of this regulation be observed during this period then;
   b) Observations must be made once every two weeks for a period of eight weeks. If a violation is noted, monitoring reverts to weekly. Should no violation of this regulation be observed during this period then;
   c) Observations must be made once per month. If a violation is noted, monitoring reverts to weekly.
3) If the source reverts to weekly monitoring at any time, monitoring frequency will progress in an identical manner from the initial monitoring frequency. If the source has already performed the weekly and biweekly monitoring and is doing semi-annual monitoring in compliance with a previous permit, the weekly and biweekly monitoring do not need to be repeated.

***Recordkeeping:***

1) The permittee shall maintain records of all observation results (see Attachment A), noting:
   a) Whether any air emissions (except for water vapor) were visible from the emission units,
   b) All emission units from which visible emissions occurred, and
   c) Whether the visible emissions were normal for the process.
2) The permittee shall maintain records of any equipment malfunctions. (See Attachment B)
3) The permittee shall maintain records of any Method 9 test performed in accordance with this permit condition. (See Attachment C)
4) Attachments A, B and C contain logs including these recordkeeping requirements. These logs, or an equivalent created by the permittee, must be used to certify compliance with this requirement.
5) These records shall be made available immediately to any Missouri Department of Natural Resources' personnel upon request.
6) All records shall be maintained for five years.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after the permittee determined, using the Method 9 test, that the emission unit exceeded the opacity limit.
2) Reports of any deviations from monitoring, recordkeeping and reporting requirements of this permit condition shall be submitted semiannually, in the semi-annual monitoring report and annual compliance certification, as required by Section V of this permit.

| **EU0020 THROUGH EU0040 – COAL HANDLING SYSTEM (EXCEPT FOR CONVEYOR #18), COAL CRUSHER HOUSE, AND FLY ASH HANDLING** | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0020 | Coal Handling System (Except for Conveyor #18) conveys and transfers coal. These coal handling units were installed prior to 1970, except for conveyor #16 and conveyor #17, which were installed in 1993 | NA | EP-03 |
| EU0030 | Coal crusher house equipped with baghouse; MHDR 700 ton/hr | NA | EP-04 |
| EU0040 | Fly ash from Boilers #1 and #2 is collected in a transfer vessel and pneumatically conveyed to silo. Fly ash from Boiler #3 is pneumatically conveyed directly from precipitator hoppers to silo. Dry fly ash is sold or sluiced in a wetted condition into holding pond. Transfer vessel and silo each equipped with fabric filter. Installed 1993. | NA | EP-06 |

## PERMIT CONDITION (EU0020 THROUGH EU0040)-001

10 CSR 10-6.220 Restriction of Emission of Visible Air Contaminants

***Emission Limitations:***

1) No owner or other person shall cause or permit emissions to be discharged into the atmosphere from any source any visible emissions with an opacity greater than 20%.
2) Exception: A person may discharge into the atmosphere from any source of emissions for a period(s) aggregating not more than six (6) minutes in any 60 minutes air contaminants with an opacity up to 60%.

***Monitoring:***

1) The permittee shall conduct opacity readings on these emission units (EU0020 through EU0040) using the procedures contained in USEPA Test Method 22. At a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by background contrast, ambient lighting, observer position relative to lighting, wind and the presence of uncombined water. Readings are only required when the emission unit is operating and when the weather conditions allow. If no visible or other significant emissions are observed using these procedures, then no further observations would be required. For emission units with visible emissions perceived or believed to exceed the applicable opacity standard, the source representative would then conduct a Method 9 observation.
2) The following monitoring schedule must be maintained:
   a) Weekly observations shall be conducted for a minimum of eight consecutive weeks after permit issuance. Should no violation of this regulation be observed during this period then-
   b) Observations must be made once every two weeks for a period of eight weeks. If a violation is noted, monitoring reverts to weekly. Should no violation of this regulation be observed during this period then-
   c) Observations must be made once per month. If a violation is noted, monitoring reverts to weekly.
3) If the source reverts to weekly monitoring at any time, monitoring frequency will progress in an identical manner from the initial monitoring frequency. If the source has already performed the weekly and biweekly monitoring and is doing monitoring in compliance with a previous permit, the weekly and biweekly monitoring do not need to be repeated.

***Recordkeeping:***

1) The permittee shall maintain records of all observation results (see Attachment A), noting:
   a) Whether any air emissions (except for water vapor) were visible from the emission units,
   b) All emission units from which visible emissions occurred, and
   c) Whether the visible emissions were normal for the process.
2) The permittee shall maintain records of any equipment malfunctions. (See Attachment B)
3) The permittee shall maintain records of any Method 9 test performed in accordance with this permit condition. (See Attachment C)
4) Attachments A, B and C contain logs including these recordkeeping requirements. These logs, or an equivalent created by the permittee, must be used to certify compliance with this requirement.
5) These records shall be made available immediately to any Missouri Department of Natural Resources' personnel upon request.
6) All records shall be maintained for five years.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after the permittee determined, using the Method 9 test, that either or both of the emission units exceeded the opacity limit.
2) Reports of any deviations from monitoring, recordkeeping and reporting requirements of this permit condition shall be submitted semiannually, in the semi-annual monitoring report and annual compliance certification, as required by Section V of this permit.

| EU0050 THROUGH EU0070 - BOILERS | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0050 | Cyclone-fired boiler; MHDR 609.6 MMBtu/hr; fired with sub-bituminous coal, bituminous coal and tire-derived fuel (TDF); equipped with dedicated electrostatic precipitator; shares stack with EU0060 and EU0070; installed 1960 | Babcock & Wilcox | EP-5A |
| EU0060 | Cyclone-fired boiler; MHDR 627.3 MMBtu/hr; fired with sub-bituminous coal, bituminous coal and tire-derived fuel (TDF); equipped with dedicated electrostatic precipitator; shares stack with EU0050 and EU0070; installed 1962 | Babcock & Wilcox | EP-5B |
| EU0070 | Cyclone-fired boiler; MHDR 4094.1 MMBtu/hr; fired with sub-bituminous coal, bituminous coal and tire-derived fuel (TDF); equipped with dedicated electrostatic precipitator; shares stack with EU0050 and EU0060; installed 1969 | Babcock & Wilcox | EP-5C |

## PERMIT CONDITION (EU0050 THROUGH EU0070)-001

10 CSR 10-2.040 Maximum Allowable Emission of Particulate Mater from Fuel Burning Equipment Used for Indirect Heating and 40 CFR Part 64 Compliance Monitoring

Note: Compliance Assurance Monitoring (CAM) applies to these units, so this permit condition incorporates parts of 40 CFR Part 64 and, through that, parts of 40 CFR Part 60. However, the Department of Natural Resources, Air Pollution Control Program, Compliance/Enforcement Section has approved a CAM plan, CAM test plan, and CAM QA/QC plan for these units. Where conflicts arise between these documents and 40 CFR Part 60, the CAM plan, CAM test plan, and CAM QA/QC plan govern. This will assure that where there is doubt, the acceptance criteria in these approved documents will be used, and not those in 40 CFR Part 60 Appendix B Performance Specification 11 (PS-11). These monitors are indicators of compliance, and not compliance monitors. The full PS-11 requirements do not apply to monitors that are only indicators of compliance.

***Emission Limitation:***

The permittee shall not emit particulate matter in excess of 0.12 pounds per million BTU's of heat input.

***Monitoring:***

1) The permittee shall install, calibrate, maintain and operate a PM continuous emission monitoring system (CEMS) in the stack to provide a reasonable assurance of the performance of the electrostatic precipitators (ESPs) in accordance with §60.13 and Appendix B to 40 CFR Part 60.

2) The PM CEMS shall be installed such that representative measurements of emissions are obtained and problems due to any detected flow disturbances or varying PM stratification are minimized. Prior to installation, measurements shall be made of flow dynamics and/or particulate matter to determine the existence or extent of PM stratification. Additional procedures for location of PM CEMS contained in Performance Specialization 11 (PS-11) of Appendix B to Part 60 shall be used.
3) The PM CEMS shall be installed and operational prior to conduction of any performance tests. The permittee shall perform verification procedures to confirm the operational status of the PM CEMS prior to the required monitoring start. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device.
4) The permittee shall establish the indicator range as the hourly average PM CEMS reading covering the full range of measurements made during the initial calibration testing plus 25%. This indicator range shall be a calibrated instrument output and shall reflect reasonable assurance of the proper operation and maintenance of the electrostatic precipitators (ESPs).
5) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including calibration checks and zero and span adjustments), the PM CEMS shall be in continuous operation and required sampling frequency shall be in accordance with §64.13(e)(2). The PM CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
6) Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for data averages and calculations, or fulfilling a minimum data availability requirement. The permittee shall use all the data collected during all other periods in assessing the operation of the ESPs and associated monitoring system.
7) The permittee shall reduce all data to one-hour averages. One-hour averages shall be computed from four or more data points equally spaced over each one-hour period.
8) Results shall be recorded on an automatic Data Acquisition Handling System (DAHS) as follows:
   a) Record the analog output of the PM CEMS;
   b) Calculate emissions values, in the units of the required standard, and according to the correlation(s) established during the PM CEMS calibration;
   c) Store the hourly averages of the calculated emissions values;
   d) Record the daily zero-span calibration results;
   e) Initiate an alarm if any daily zero or span value exceeds the error limit of plus or minus 5%;
   f) Exceedances - initiate an alarm if the hourly averaged PM CEMS emission value reaches or exceeds the lower of the following limits:
      i) A value equivalent to 1.25 times the highest PM CEMS response value reached during the correlation tests, or
      ii) A value equivalent to 0.9 times the source emission limit; and,
   g) Initiate an alarm on the occurrence of a malfunction status indicator from the PM CEMS.
9) Upon detecting an exceedance, the permittee shall restore operation of EU0050 through EU0070 (including the ESPs and associated capture system) to their normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Operational checks shall be made as soon as practicable and may include:
   a) ESP field checks (T/R voltage, current, spark rate);

b) Visual inspection of control equipment;
c) Unusual fuel characteristics; and,
d) Boiler upset conditions.

10) Quality Assurance and Control Practices (QA/QC)
   a) Factory supplied filter standards will be used to calibrate the instruments at a reference zero and upscale span value. These calibration standards will be maintained in accordance with manufacturer's recommendations. Following the calibration an internal zero-span cycle will be initiated, thus establishing initial values for future reference.
   b) Daily zero-span cycles will be performed with the results stored in the data system and compared with the initial values.
   c) Should either the zero or span value error exceed plus or minus 5% of the starting value, an alarm will be initiated and the permittee shall recalibrate the instrument to the factory standards.
   d) A quarterly reference calibration will be performed as described in the instrument operations manual. The factory standards will be used to measure instrument response at a zero and upscale value. Should either of these readings exceed the factory standard by more than plus or minus 5% of the full-scale measurement range, the instrument will be reset to the factory standard values.
   e) Routine scheduled maintenance procedures will be established in accordance with manufacturer's recommendations.

11) If the accumulation of exceedances or excursions exceeds 5% of operating time for a reporting period, the permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the permittee shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:
   a) Improved preventive maintenance practices;
   b) Process operation changes;
   c) Appropriate improvements to control methods;
   d) Other steps appropriate to correct control performance;
   e) More frequent or improved monitoring.

12) The permittee shall begin the monitoring required under this permit condition within 180 days after the approval of the Part 70 renewal operating permit.

13) The permittee shall maintain monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment, at all times.

***Testing:***

1) The instruments shall be calibrated based on the boiler load, coal, and ESPs characteristics and any other performance or test data deemed applicable by the permittee and/or director. Reference method measurements will be conducted in accordance with accepted method standards and compared with the integrated (arithmetic average) PM CEMS output over the reference method test period.

2) Correlation/Performance Testing
   a) The PM CEMS shall be initially operated for a period of approximately 30 days under various operating conditions to identify condition necessary to produce two target concentration levels for the correlation testing. During the 30 day pre-test monitoring period the following key operating parameters will be recorded on each stack:
      i) Monitor output;
      ii) Plant load;

iii) Fuel type;
iv) ESP voltage and current readings.

b) A minimum of twelve (12) valid runs (e.g. 2 loads, 2 fuel blends and 3 tests per condition) will be required to obtain the correlation equation and correlation coefficient. A run will be declared "not valid" only when performed during a time when conditions are clearly not representative of normal operations. The linear correlation will be determined according to Equation 11-3 of Performance Specification 11 of Appendix B to Part 60. The correlation coefficient will be calculated according to Equation 11-14 of Performance Specification 11 of Appendix B to Part 60.
c) Tests shall be performed at two different PM concentration levels, with a minimum of three tests at each level, if possible. Level 1 encompasses the range from 0 to 50% of the maximum PM concentration available. Level 2 should range from 75% to 100% of the maximum concentration. The source should be operated over the complete range of expected conditions, so as to assure that the data produced is representative. The data gathered during the 30-day pretest monitoring period shall be used to produce the desired concentrations for the test runs.
d) During correlation testing, the reference method data and PM CEMS measurements will be converted into units of pounds PM per MMBtu to establish limits comparable to the emission limitation of 0.12 lb PM/MMBtu. Once established, these limits will be converted into units of pounds PM per actual stack gas volume, or pounds of PM per megawatt. During operation after testing, the PM CEMS output and determination of PM levels with respect to limits will be conducted only in units of pounds per actual stack gas volume or pounds PM per megawatt.
e) The correlation coefficient (r) resulting from the calibration testing must be greater than or equal to 0.75.
f) Once the correlation equation has been determined, it shall be applied to PM CEMS data collected by the Data Recorder.

***Recordkeeping:***

1) The permittee shall comply with the recordkeeping requirements specified in §70.6(a)(3)(ii) including records of required monitoring information that include the following:
   a) The date, place, and time of sampling or measurements;
   b) The date(s) analyses were performed;
   c) If applicable, the company or entity that performed the analyses;
   d) The analytical techniques or methods used;
   e) The results of such analyses; and
   f) The operating conditions as existing at the time of sampling or measurement.
2) The permittee shall maintain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all required calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all required reports (including any written Quality Improvement Plan (QIP)).
3) The permittee may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, instead of paper provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.
4) Following any exceedance, the permittee shall record that operations returned to normal without operator action, or any necessary follow-up actions to return operation to within the indicator range.

5) These records shall be made available immediately to any Missouri Department of Natural Resources' personnel upon request.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after any deviations/exceedances of this permit condition.
2) Performance Testing.
   a) The permittee shall submit operating parameter data obtained during the conduct of any applicable compliance or performance tests.
   b) The permittee shall submit documentation that no changes to the emission units, including the control device and capture system, have taken place that could result in a significant change in the control system performance or selected indicator ranges since the last performance or compliance test.
3) If the permittee identifies a failure to achieve compliance with the PM emissions limit for which the PM CEMS did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges, the permittee shall promptly notify the MDNR and, if necessary, submit a proposed modification to the Part 70 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
4) The permittee shall submit quarterly monitoring reports certified by a responsible official. The monitoring report shall include, as a minimum, the following information, as applicable:
   a) All instances of deviations from permit requirements must be clearly identified.
   b) Prompt reporting of deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken.
   c) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   d) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   e) A description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period as specified in §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

## PERMIT CONDITION (EU0050 THROUGH EU0070)-002

10 CSR 10-6.220 Restriction of Emission of Visible Air Contaminants

***Emission Limitations:***

1) No owner or other person shall cause or permit emissions to be discharged into the atmosphere from any existing source any visible emissions with an opacity greater than 20%.
2) Exception: A person may discharge into the atmosphere from any source of emissions for a period(s) aggregating not more than six (6) minutes in any 60 minutes air contaminants with an opacity up to 60%.

***Monitoring/Operational Requirements:***

1) A continuous opacity monitoring system shall be installed, calibrated, maintained, and operated in accordance with 40 CFR Part 60, Appendix B - Performance Specification 1.
2) COMS General Requirements
   a) Source operating time includes any time fuel is being combusted and/or a fan is being operated.
   b) Cycling times include the total time a monitoring system requires to sample, analyze and record an emission measurement. Continuous monitoring systems for measuring opacity shall complete a minimum of one cycle of operating (sampling and analyzing) for each successive ten-second period and one cycle of data recording for each successive six-minute period.
   c) The COMS shall be certified by the director of the Air Pollution Control Program after review and acceptance of a demonstration of conformance with 40 CFR Part 60, Appendix B - Performance Specification 1.
   d) The COMS shall be subject to audits conducted by the Missouri Department of Natural Resources, and all COMS records shall be made available immediately upon request to department personnel.

***Recordkeeping:***

1) The permittee shall maintain a file (hard copy or electronic version) of the following information for a minimum of five years from the date the data was collected:
   a) All information reported in the quarterly summaries including:
      i) The charts or printouts generated by the COMS, where applicable;
      ii) An opacity summary report;
      iii) An excess opacity emission summary;
      iv) An excess opacity emission summary list;
      v) An opacity monitoring downtime summary list; and
   b) All six-minute opacity averages and daily Quality Assurance (QA)/Quality Control (QC) records. This includes, but is not restricted to the daily monitoring system calibration check done on the continuous opacity monitoring system.
2) The permittee shall maintain records of any opacity monitoring equipment malfunctions.
3) The permittee shall maintain records of any Method 9 test performed in accordance with this permit condition. Attachment C or equivalent recordkeeping form shall be used to provide Method 9 Visual Observation log records.
4) These records shall be made available immediately for inspection to any Missouri Department of Natural Resources' personnel upon request.
5) All records shall be maintained for five years.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after any exceedance of the opacity limit established by this permit condition.
2) The permittee shall submit a quarterly written report to the Missouri Department of Natural Resources Air Pollution Control Program. All quarterly reports shall be postmarked no later than the thirtieth day following the end of each calendar quarter and shall included the following emissions data:
   a) A summary including total time for each cause of excess emissions and/or monitor downtime;
   b) Nature and cause of excess emissions, if known;

c) The six-minute average opacity values greater than the opacity emission requirements (the average of the values shall be obtained by using the procedures specified in the Reference Method used to determine the opacity of the visible emissions);
d) The date and time identifying each period during which the COMS was inoperative (except for zero and span checks), including the nature and frequency of system repairs of adjustments that were made during these times; and
e) If no excess emissions have occurred during the reporting period and the COMS has not been inoperative, repaired or adjusted, this information shall be stated in the report.

## PERMIT CONDITION (EU0050 THROUGH EU0070)-003

10 CSR 10-6.260 Restriction of Emission of Sulfur Compounds

***Emission Limitations:***

1) Aquila - Sibley Plant shall not cause or allow emissions of sulfur dioxide into the atmosphere in excess of nine pounds (9 lbs) of sulfur dioxide ($SO_2$) per million Btus actual heat input averaged on any consecutive three (3)-hour time period.
2) No person shall cause or permit the emission of sulfur compounds from any source which causes or contributes to concentrations exceeding those specified in 10 CSR 10-6.010 Ambient Air Quality Standards.

| Pollutant | Concentration by Volume | Remarks |
|---|---|---|
| Sulfur Dioxide ($SO_2$) | 0.03 parts per million (ppm) (80 micrograms per cubic meter ($\mu g/m^3$)) | Annual arithmetic mean |
| | 0.14 ppm (365 $\mu g/m^3$) | 24-hour average not to be exceeded more than once per year |
| | 0.5 ppm (1300 $\mu g/m^3$) | 3-hour average not to be exceeded more than once per year |
| Hydrogen Sulfide ($H_2S$) | 0.05 ppm (70 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times per year |
| | 0.03 ppm (42 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times in any 5 consecutive days |
| Sulfuric Acid ($H_2SO_4$) | 10 $\mu g/m^3$ | 24-hour average not to be exceeded more than once in any 90 consecutive days |
| | 30 $\mu g/m^3$ | 1-hour average not to be exceeded more than once in any 2 consecutive days |

***Monitoring:***

1) The permittee shall maintain and operate a continuous emission monitoring system (CEMS) in accordance with all the requirements of 40 CFR Part 75 to monitor $SO_2$ emissions. Results shall be recorded on an automated Data Acquisition Handling System (DAHS).
2) The permittee shall ensure that the CEMS meets the equipment, installation, and performance specifications in Appendix A to 40 CFR Part 75; and is maintained according to the quality assurance and quality control procedures in Appendix B to 40 CFR Part 75.
3) The permittee shall ensure that the CEMS is in operation and monitoring unit emissions at all times that the affected units (EU0050 through EU0070) combust any fuel except during periods of

calibration, quality assurance, or preventative maintenance, as well as, periods of repair, periods of backups of data from the DAHS or recertification.

4) The permittee shall ensure that the CEMS is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. The permittee shall reduce all $SO_2$ emissions data to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance, or backups of data from the DAHS, or recertification. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.
5) The permittee shall prepare and maintain a monitoring plan in accordance with §75.53. A monitoring plan shall contain sufficient information on the CEMS to demonstrate that all $SO_2$ emissions are monitored and reported.
6) Whenever the permittee makes a replacement, modification, or change in the certified CEMS, including a change in the automated DAHS or in the flue gas handling system, that affects information reported in the monitoring, then the permittee shall update the monitoring plan, by the applicable deadline specified in §75.62.

***Recordkeeping:***

1) The permittee shall maintain a file on-site of all measurements, data, reports, and other information required by §75.53, §75.57 and §75.59. Records include the following:
   a) Total fuel consumed during the control period;
   b) The total heat input for each emissions unit during the control period;
   c) Reports of all stack testing conducted;
   d) All other data collected by a CEMS necessary to convert the monitoring data to the units of the applicable emission limitation;
   e) All performance evaluations conducted in the past year;
   f) All monitoring device calibration checks;
   g) All monitoring system, monitoring device and performance testing measurements;
   h) Records of adjustments and maintenance performed on monitoring systems and devices; and
   i) A log identifying each period during which the CEMS or alternate procedure was inoperative, except for zero and span checks, and the nature of the repairs and adjustments performed to make the system operative.
2) These records shall be made available immediately to any Missouri Department of Natural Resources' personnel upon request.
3) These records shall be kept in a form suitable for inspection for at least five years.

***Reporting:***

1) The permittee shall submit all quarterly reports required by Part 75. The reports are due within 30 days after the end of each calendar quarter. The quarterly reports must include the following essential information:
   a) Facility information in accordance with §75.64(a)(1);
   b) Hourly and cumulative emissions data;
   c) Hourly unit operating information (e.g., load, heat input rate, operating time, etc.);

d) Monitoring plan information;
e) Results of required quality-assurance tests (e.g., daily calibrations, linearity checks, RATAs, etc.); and
f) Certification statements from the Designated Representative or Authorized Account Representative (or the Alternate Representative), attesting to the completeness and accuracy of the data.

2) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after any deviations/exceedances of this permit condition.

## PERMIT CONDITION (EU0050 THROUGH EU0070)-004

10 CSR 10-6.270 Acid Rain Source Permits Required

***Emission Limitation:***

The permittee shall obtain an Acid Rain Source Permit for EU0050 through EU0070 pursuant to Title IV of the Clean Air Act.

A Phase II permit (Missouri Department of Natural Resources project EX095-0031-021, ORIS Code 2094) was issued to the permittee on February 9, 1998, with effective dates from January 1, 2000 to December 31, 2004. Sulfur dioxide ($SO_2$) limitations are referenced in this existing Title IV: Phase II Acid Rain Permit for the installation. The permittee submitted a renewal application on June 25, 2004, under 10 CSR 10-6.270, *Acid Rain Source Permits Required.* No changes to the installation's status were reflected in this renewal application.

***Monitoring/Recordkeeping:***

The permittee shall retain the most current acid rain permit issued to this installation on-site and shall immediately make such permit available to any Missouri Department of Natural Resources' personnel upon request.

***Reporting:***

Annual Compliance Certification

## PERMIT CONDITION (EU0050 THROUGH EU0070)-005

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

***Emission Limitations:***

1) The permittee shall limit emissions of $NO_X$ to the rate of 0.68 lbs. $NO_X$ /million British thermal units (MMBtu) of heat input during any control period in a year during which the three boilers (EU0050 through EU0070) together burn tire-derived fuel in a quantity of at least three hundred thousand (300,000) passenger tire equivalents. A control period is the period beginning May 1 of a calendar year and ending on September 30 of the same year.
2) The permittee shall limit emissions of $NO_X$ to the rate of 0.35 lbs. $NO_X$ /million British thermal units (MMBtu) of heat input during any control period in a year during which the three boilers (EU0050 through EU0070) together do not burn tire-derived fuel in a quantity of at least three hundred thousand (300,000) passenger tire equivalents. A control period is the period beginning May 1 of a calendar year and ending on September 30 of the same year.
3) In lieu of complying with the above emission limit, the permittee may comply through the $NO_X$ emissions trading program under 10 CSR 10-6.350(3)(B).

a) Compliance with this rule shall not relieve the permittee of the responsibility to comply fully with applicable provisions of the Air Conservation Law and rules or any other requirements under local, state or federal law. Specifically, compliance with 10 CSR 10-6.350 shall not violate the permit conditions previously established under 10 CSR 10-6.060 or 10 CSR 10-6.065.

***Monitoring:***

1) Compliance shall be measured during the control period.
2) All valid data shall be used for calculating $NO_X$ emissions rates.
3) Any coal-affected unit shall install, certify, operate, maintain, and quality assure a $NO_X$ and diluent CEMS pursuant to the requirements in 40 CFR Part 75;

***Recordkeeping:***

1) The permittee shall maintain records of the following:
   a) Total fuel consumed during the control period;
   b) The total heat input for each emissions unit during the control period;
   c) Reports of all stack testing conducted to meet the requirements of this rule;
   d) All other data collected by a CEMS necessary to convert the monitoring data to the units of the applicable emission limitation;
   e) All performance evaluations conducted in the past year;
   f) All monitoring device calibration checks;
   g) All monitoring system, monitoring device and performance testing measurements;
   h) Records of adjustments and maintenance performed on monitoring systems and devices; and
   i) A log identifying each period during which the CEMS or alternate procedure was inoperative, except for zero and span checks, and the nature of the repairs and adjustments performed to make the system operative.
2) These records shall be made available immediately to any Missouri Department of Natural Resources' personnel upon request.
3) All records shall be kept on-site for a period of five years.

***Reporting***:

1) A compliance certification report for each affected unit shall be submitted to the Missouri Department of Natural Resources by October 31 following each control period. The report shall include:
   a) The owner and operator;
   b) The $NO_X$ authorized account representative;
   c) $NO_X$ unit name, compliance and overdraft account numbers;
   d) $NO_X$ emission rate limitation (lb/MMBtu);
   e) Actual $NO_X$ emission rate (lb/MMBtu) for the control period;
   f) Actual heat input (MMBtu) for the control period. The unit's total heat input for the control period in each year will be determined in accordance with the test methods and monitoring requirements;
   g) Actual $NO_X$ mass emissions (tons) for the control period.
2) The $NO_X$ authorized account representatives seeking the recording of a $NO_X$ allowance transfer shall submit the transfer request to the director. To be considered correctly submitted, the $NO_X$ allowance transfer shall include the following elements in a format specified by the director:
   a) The numbers identifying both the transferor and transferee accounts;

b A specification by serial number of each $NO_X$ allowance to be transferred; and

c) The printed name and signature of the $NO_X$ authorized account representative of the transferor account and the date signed.

3) Any unit with valid CEMS data for the control period must use that data to determine compliance with the provisions of 10 CSR 10-6.350.

4) The permittee shall report any deviations/exceedances of this permit condition using the semi-annual monitoring report and annual compliance certification to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as required by Section V of this permit.

| EU0080 THROUGH EU0110 – EMERGENCY GENERATOR, WELDING MACHINES, AND BACK-UP DIESEL FIRE PUMP | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0080 | No. 2 distillate-fired emergency generator; MHDR 4.39 MMBtu/hr; installed 1969 | Fairbanks | EP-07 |
| EU0090 | Gasoline fired, portable welding machine; MHDR 0.077 MMbtu/hr; installed 2001 | Onan | EP-08 |
| EU0100 | Gasoline fired, portable welding machine; MHDR 0.14 MMbtu/hr; installed 2001 | Airco | EP-09 |
| EU0110 | Backup diesel fired fire pump; MHDR 0.847 MMBtu/hr; installed 1988 | Caterpillar | EP-11 |

## PERMIT CONDITION (EU0080 THROUGH EU0110)-001

10 CSR 10-6.260 Restriction of Emission of Sulfur Compounds

***Emission Limitation:***

1) Emissions from EU0080 shall not contain more than two thousand parts per million by volume (2000 ppmv) of sulfur dioxide.
2) Emissions from EU0090 through EU0110 shall not contain more than five hundred parts per million by volume (500 ppmv) of sulfur dioxide.
3) Stack gasses from EU0080 shall not contain more than seventy milligrams (70 mg) per cubic meter of sulfuric acid or sulfur trioxide or any combination of those gases averaged on any consecutive three hour time period.
4) Stack gasses from EU0090 through EU0110 shall not contain more than thirty-five milligrams (35 mg) per cubic meter of sulfuric acid or sulfur trioxide or any combination of those gases averaged on any consecutive three hour time period.
5) No person shall cause or permit the emission of sulfur compounds from any source which causes or contributes to concentrations exceeding those specified in 10 CSR 10-6.010 Ambient Air Quality Standards.

| Pollutant | Concentration by Volume | Remarks |
|---|---|---|
| Sulfur Dioxide ($SO_2$) | 0.03 parts per million (ppm) (80 micrograms per cubic meter ($\mu g/m^3$)) | Annual arithmetic mean |
| | 0.14 ppm (365 $\mu g/m^3$) | 24-hour average not to be exceeded more than once per year |
| | 0.5 ppm (1300 $\mu g/m^3$) | 3-hour average not to be exceeded more than once per year |
| Hydrogen Sulfide ($H_2S$) | 0.05 ppm (70 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times per year |
| | 0.03 ppm (42 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times in any 5 consecutive days |
| Sulfuric Acid ($H_2SO_4$) | 10 $\mu g/m^3$ | 24-hour average not to be exceeded more than once in any 90 consecutive days |
| | 30 $\mu g/m^3$ | 1-hour average not to be exceeded more than once in any 2 consecutive days |

***Operational Limitation/Equipment Specification:***
Emission unit EU0080 shall be limited to burning Number 2 diesel fuel oil with a sulfur content of 1.5 percent (%) by weight or less.

***Monitoring/Recordkeeping:***
1) The permittee shall maintain an accurate record of the sulfur content of fuel used in EU0080. Fuel purchase receipts, analyzed samples or certifications that verity the fuel type and sulfur content will be acceptable.
2) The permittee is assumed to be in compliance with this regulation as long as emission unit EU0080 burns fuel oil with a sulfur content of 1.5 % by weight or less. Calculations demonstrating this are in Attachment E. The permittee shall keep this attachment with this permit.
3) These records shall be made available immediately to any Missouri Department of Natural Resources' personnel upon request.
4) All records shall be maintained for five years.

***Reporting:***
Reports of any deviations from monitoring, recordkeeping and reporting requirements of this permit condition shall be submitted semiannually, in the semi-annual monitoring report and annual compliance certification, as required by Section V of this permit.

| EU0120 AND EU0130 – PARTS WASHER AND SPRAY PAINT BOOTH | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0120 | Parts Washer | Safety Kleen | EP-10 |
| EU0130 | Spray Paint Booth | NA | EP-12 |

## PERMIT CONDITION (EU0120 and EU0130)-001

10 CSR 10-6.060 Construction Permits Required
Construction Permit #0897-025 Issued 8/04/1997

***Emission Limitation:***

The permittee shall not emit more than 12.0 tons of volatile organic compounds (VOC) during any consecutive 12-month period from the following: Safety Kleen parts washer identified as EU0120 and 2) spray paint booth identified as EU0130. [Special Condition 1]

***Recordkeeping:***

The permittee shall maintain an accurate monthly record of VOC emissions from the Safety Kleen parts washer identified as EU0120 and the spray paint booth identified as EU0130. These records shall include monthly and cumulative 12-month totals. These records shall be kept on-site for the most recent 60-month period of operation and be made immediately available to Missouri Department of Natural Resources' personnel upon request. These records shall be on Attachment D or on any substantially conforming form that contains the same information. [Special Condition 2]

***Reporting:***

The permittee shall report to the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after the end of each month, if the 12-month cumulative total records (Condition Number 2) show that the Source exceeded the limitation of Condition Number 1. [Special Condition 3]

## PERMIT CONDITION EU0120-002

10 CSR 10-2.210 Control of Emissions from Solvent Metal Cleaning

***Equipment and Operating Parameters:***

1) The permittee shall not allow the operation of any cold cleaner using a cold cleaning solvent with a vapor pressure greater than 1.0 millimeters of Mercury (0.019 psi) at twenty degrees Celsius (20°C).
2) Each cold cleaner shall have:
   a) A cover which will prevent the escape of solvent vapors from the solvent bath while in the closed position, or an enclosed reservoir that will prevent the escape of solvent vapors from the solvent bath whenever parts are not being processed in the cleaner.
   b) When one or more of the following conditions exist, the design of the cover shall be such that it can be easily operated with one hand such that minimal disturbing of the solvent vapors in the tank occurs. (For covers larger than ten square feet, this shall be accomplished by either mechanical assistance such as spring loading or counterweighing or by power systems):
      i) The solvent volatility is greater than 0.3 psi measured at one hundred degrees Fahrenheit (100°F), such as in mineral spirits;
      ii) The solvent is agitated; or
      iii) The solvent is heated.
   c) An external drainage installation which provides for the solvent to drain back into the solvent bath.
   d) If an internal drainage facility cannot fit into the cleaning system and the solvent volatility is less than 0.6 psi measured at one hundred degrees Fahrenheit (100°F), then the cold cleaner shall have an external drainage facility which provides for the solvent to drain back into the solvent bath.
   e) Solvent sprays, if used, shall be a solid fluid stream and operate at a pressure which does not cause any splashing above or beyond the freeboard.

f) A permanent conspicuous label summarizing the operating procedures shall be affixed to the equipment.
g) Any cold cleaner which uses a solvent that has a solvent volatility greater than 0.6 psi measured at one hundred degrees Fahrenheit (100°F) or heated above one hundred twenty degrees Fahrenheit (120°F) must use one of the following control devices:
   i) A freeboard ratio of at least 0.75;
   ii) Water cover (solvent must be insoluble in and heavier than water); or
   iii) Other control systems with a mass balance demonstrated overall VOC emissions reduction efficiency greater than or equal to sixty-five percent (65%). These control systems must receive approval from the director prior to their use

3) Each cold cleaner shall be operated as follows:
   a) Cold cleaner covers shall be closed whenever parts are not being handled in the cleaners or the solvent must drain into an enclosed reservoir.
   b) Cleaned parts shall be drained in the freeboard area for at least fifteen (15) seconds or until dripping ceases, whichever is longer.
   c) Whenever a cold cleaner fails to perform within the operating parameters established for it by this regulation, the unit shall be shut down immediately and shall remain shut down until trained service personnel are able to restore operation within the established parameters.
   d) Solvent leaks shall be repaired immediately or the degreaser shall be shut down until the leaks are repaired.
   e) Any waste material removed from a cold cleaner shall be disposed of by one of the following methods and in accordance with the Missouri Hazardous Waste Management Commission rules codified at 10 CSR 10-25, as applicable:
      i) Reduction of the waste material to less than twenty percent (20%) VOC solvent by distillation and proper disposal of the still bottom waste, or
      ii) Stored in closed containers for transfer to a contract reclamation service or a disposal installation approved by the director.
4) Waste solvent shall be stored in covered containers only.
5) Operators must be trained as follows:
   a) Only persons trained in at least the operational and equipment requirements specified in this regulation for their particular solvent metal cleaning process shall be permitted to operate the equipment,
   b) The supervisor of any person who operates a solvent metal cleaning process shall receive equal or greater operational training than the operator,
   c) Refresher training shall be given to all solvent metal cleaning equipment operators at least once each twelve month period.
   d) A record shall be kept of solvent metal cleaning training for each employee.

***Monitoring:***
The permittee shall monitor the throughputs of the solvents monthly and maintain material safety data sheets (MSDS) of the cleanup solvents used at the installation. The permittee may use electronic database sources for MSDS storage and retrieval.

***Recordkeeping***
1) The permittee shall keep monthly inventory records of solvent types and amounts purchased and solvent consumption. These records shall include all types and amounts of solvent containing waste

material transferred to either a contract reclamation service or to a disposal installation and all amounts distilled on the premises. These records also shall include maintenance and repair logs.

2) The permittee shall maintain records which include for each purchase of cold cleaning solvent:
   a) The name and address of the solvent supplier;
   b) The date of purchase;
   c) The type of solvent; and
   d) The vapor pressure of the solvent in mmHg at twenty degrees Celsius (20°C) (sixty-eight degrees Fahrenheit (68°F)).
3) A record shall be kept of solvent metal cleaning training for each employee.
4) These records shall be made available immediately for inspection to any Missouri Department of Natural Resources' personnel upon request.
5) All records shall be maintained for five years.

***Reporting:***

The permittee shall report to the Air Pollution Control Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after any deviation from or exceedance of any of the terms imposed by this regulation, or any malfunction which causes a deviation from or exceedance of this regulation.

## PERMIT CONDITION EU0130-002

10 CSR 10-2.210 Control of Emissions from Solvent Metal Cleaning

***Equipment and Operation Parameters:***

1) Paint spray guns and nozzles only may be cleaned in solvent-based materials capable of stripping hardened paint, provided the solvent reservoir (not to exceed five gallons in size) is kept tightly covered at all times except when being accessed.
2) A permanent conspicuous label summarizing the operating procedures for cleaning the paint gun and nozzle shall be affixed to the paint booth.
3) Whenever cleaning of the paint gun and nozzle fails to perform within the operating parameters established for it by this rule, the cleaning operation shall be shut down immediately and shall remain shut down until trained service personnel are able to restore operation within the established parameters.
4) Solvent leaks shall be repaired immediately or cleaning operations shall be shut down until the leaks are repaired.
5) Any waste material removed from cleaning operation shall be disposed of by one of the following methods and in accordance with the Missouri Hazardous Waste Management Commission rules codified at 10 CSR 10-25, as applicable:
   a) Reduction of the waste material to less than twenty percent (20%) VOC solvent by distillation and proper disposal of the still bottom waste, or
   b) Stored in closed containers for transfer to a contract reclamation service or a disposal facility approved by the director.
6) Waste solvent shall be stored in covered containers only.
7) Operators must be trained as follows:
   a) Only persons trained in at least the operational and equipment requirements specified in this rule for their particular solvent metal cleaning process shall be permitted to operate the equipment,

b) The supervisor of any person who operates a solvent metal cleaning process shall receive equal or greater operational training than the operator, Refresher training shall be given to all solvent metal cleaning equipment operators at least once each 12 month period.

***Monitoring/Recordkeeping:***

1) The permittee shall keep monthly inventory records of solvent types and amounts purchased and solvent consumption. These records shall include all types and amounts of solvent containing waste material transferred to either a contract reclamation service or to a disposal installation and all amounts distilled on the premises. These records also shall include maintenance and repair logs.
2) The permittee shall maintain records which include for each purchase of cold cleaning solvent:
   a) The name and address of the solvent supplier;
   b) The date of purchase;
   c) The type of solvent; and
   d) The vapor pressure of the solvent in mmHg at twenty degrees Celsius (20°C) (sixty-eight degrees Fahrenheit (68°F)).
3) A record shall be kept of solvent metal cleaning training for each employee.
4) These records shall be made available immediately for inspection to any Missouri Department of Natural Resources' personnel upon request.
5) All records shall be maintained for five years.

***Reporting:***

The permittee shall report to the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after any deviation from or exceedance of any of the terms imposed by this regulation, or any malfunction which causes a deviation from or exceedance of this regulation.

# IV. Core Permit Requirements

The installation shall comply with each of the following requirements. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued.

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

1) In the event of a malfunction, which results in excess emissions that exceed one hour, the permittee shall submit to the director within two business days, in writing, the following information:
   a) Name and location of installation;
   b) Name and telephone number of person responsible for the installation;
   c) Name of the person who first discovered the malfunction and precise time and date that the malfunction was discovered.
   d) Identity of the equipment causing the excess emissions;
   e) Time and duration of the period of excess emissions;
   f) Cause of the excess emissions;
   g) Air pollutants involved;
   h) Best estimate of the magnitude of the excess emissions expressed in the units of the applicable requirement and the operating data and calculations used in estimating the magnitude;
   i) Measures taken to mitigate the extent and duration of the excess emissions; and
   j) Measures taken to remedy the situation that caused the excess emissions and the measures taken or planned to prevent the recurrence of these situations.
2) The permittee shall submit the paragraph 1 information list to the director in writing at least ten days prior to any maintenance, start-up or shutdown, which is expected to cause an excessive release of emissions that exceed one hour. If notice of the event cannot be given ten days prior to the planned occurrence, it shall be given as soon as practicable prior to the release. If an unplanned excess release of emissions exceeding one hour occurs during maintenance, start-up or shutdown, the director shall be notified verbally as soon as practical during normal working hours and no later than the close of business of the following working day. A written notice shall follow within ten working days.
3) Upon receipt of a notice of excess emissions issued by an agency holding a certificate of authority under section 643.140, RSMo, the permittee may provide information showing that the excess emissions were the consequence of a malfunction, start-up or shutdown. The information, at a minimum, should be the paragraph 1 list and shall be submitted not later than 15 days after receipt of the notice of excess emissions. Based upon information submitted by the permittee or any other pertinent information available, the director or the commission shall make a determination whether the excess emissions constitute a malfunction, start-up or shutdown and whether the nature, extent and duration of the excess emissions warrant enforcement action under section 643.080 or 643.151, RSMo.
4) Nothing in this rule shall be construed to limit the authority of the director or commission to take appropriate action, under sections 643.080, 643.090 and 643.151, RSMo to enforce the provisions of the Air Conservation Law and the corresponding rule.
5) Compliance with this rule does not automatically absolve the permittee of liability for the excess emissions reported.

**10 CSR 10-6.060 Construction Permits Required**

The permittee shall not commence construction, modification, or major modification of any installation subject to this rule, begin operation after that construction, modification, or major modification, or begin operation of any installation which has been shut down longer than five years without first obtaining a permit from the permitting authority.

**10 CSR 10-6.065 Operating Permits**

The permittee shall file a complete application for renewal of this operating permit at least six months before the date of permit expiration. In no event shall this time be greater than eighteen months. [10 CSR 10-6.065(6)(B)1.A(V)] The permittee shall retain the most current operating permit issued to this installation on-site. [10 CSR 10-6.065(6)(C)1.C(II)] The permittee shall immediately make such permit available to any Missouri Department of Natural Resources personnel upon request. [10 CSR 10-6.065(6)(C)3.B]

**10 CSR 10-6.110 Submission of Emission Data, Emission Fees and Process Information**

1) The permittee shall complete and submit an Emission Inventory Questionnaire (EIQ) in accordance with the requirements outlined in this rule.
2) The permittee shall pay an annual emission fee per ton of regulated air pollutant emitted according to the schedule in the rule. This fee is an emission fee assessed under authority of RSMo. 643.079 to satisfy the requirements of the Federal Clean Air Act, Title V.
3) The fees shall be due April 1 each year for emissions produced during the previous calendar year. The fees shall be payable to the Department of Natural Resources and shall be accompanied by the Emissions Inventory Questionnaire (EIQ) form or equivalent approved by the director.

**10 CSR 10-6.130 Controlling Emissions During Episodes of High Air Pollution Potential**

This rule specifies the conditions that establish an air pollution alert (yellow/orange/red/purple), or emergency (maroon) and the associated procedures and emission reduction objectives for dealing with each. The permittee shall submit an appropriate emergency plan if required by the Director.

**10 CSR 10-6.150 Circumvention**

The permittee shall not cause or permit the installation or use of any device or any other means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission or air contaminant which violates a rule of the Missouri Air Conservation Commission.

**10 CSR 10-6.170 Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin**

1) The permittee shall not cause or allow to occur any handling, transporting or storing of any material; construction, repair, cleaning or demolition of a building or its appurtenances; construction or use of a road, driveway or open area; or operation of a commercial or industrial installation without applying reasonable measures as may be required to prevent, or in a manner which allows or may allow, fugitive particulate matter emissions to go beyond the premises of origin in quantities that the particulate matter may be found on surfaces beyond the property line of origin. The nature or origin of the particulate matter shall be determined to a reasonable degree of certainty by a technique proven to be accurate and approved by the director.
2) The permittee shall not cause nor allow to occur any fugitive particulate matter emissions to remain visible in the ambient air beyond the property line of origin.

3) Should it be determined that noncompliance has occurred, the director may require reasonable control measures as may be necessary. These measures may include, but are not limited to, the following:
   a) Revision of procedures involving construction, repair, cleaning and demolition of buildings and their appurtenances that produce particulate matter emissions;
   b) Paving or frequent cleaning of roads, driveways and parking lots;
   c) Application of dust-free surfaces;
   d) Application of water; and
   e) Planting and maintenance of vegetative ground cover.

**10 CSR 10-6.180 Measurement of Emissions of Air Contaminants**

1) The director may require any person responsible for the source of emission of air contaminants to make or have made tests to determine the quantity or nature, or both, of emission of air contaminants from the source. The director may specify testing methods to be used in accordance with good professional practice. The director may observe the testing. Qualified personnel shall perform all tests.
2) The director may conduct tests of emissions of air contaminants from any source. Upon request of the director, the person responsible for the source to be tested shall provide necessary ports in stacks or ducts and other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants.
3) The director shall be given a copy of the test results in writing and signed by the person responsible for the tests.

**10 CSR 10-2.100 Open Burning Restrictions**

1) The permittee shall not conduct, cause, permit or allow a salvage operation, the disposal of trade wastes or burning of refuse by open burning.
2) Exception - Open burning of trade waste or vegetation may be permitted only when it can be shown that open burning is the only feasible method of disposal or an emergency exists which requires open burning.
3) Any person intending to engage in open burning shall file a request to do so with the director. The request shall include the following:
   a) The name, address and telephone number of the person submitting the application; The type of business or activity involved; A description of the proposed equipment and operating practices, the type, quantity and composition of trade wastes and expected composition and amount of air contaminants to be released to the atmosphere where known;
   b) The schedule of burning operations;
   c) The exact location where open burning will be used to dispose of the trade wastes;
   d) Reasons why no method other than open burning is feasible; and
   e) Evidence that the proposed open burning has been approved by the fire control authority which has jurisdiction.
4) Upon approval of the open burning permit application by the director, the person may proceed with the operation under the terms of the open burning permit. Be aware that such approval shall not exempt Aquila – Sibley Generating Station from the provisions of any other law, ordinance or regulation.
5) The permittee shall maintain files with letters from the director approving the open burning operation and previous DNR inspection reports.

**10 CSR 10-2.070 Restriction of Emission of Odors**

No person may cause, permit or allow the emission of odorous matter in concentrations and frequencies or for durations that odor can be perceived when one volume of odorous air is diluted with seven volumes of odor-free air for two separate trials not less than 15 minutes apart within the period of one hour.

**This requirement is not federally enforceable.**

**Title VI – 40 CFR Part 82 Protection of Stratospheric Ozone**

1) The permittee shall comply with the standards for labeling of products using ozone-depleting substances pursuant to 40 CFR Part 82, Subpart E:
   a) All containers in which a class I or class II substance is stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced into interstate commerce pursuant to §82.106.
   b) The placement of the required warning statement must comply with the requirements pursuant to §82.108.
   c) The form of the label bearing the required warning statement must comply with the requirements pursuant to §82.110.
   d) No person may modify, remove, or interfere with the required warning statement except as described in §82.112.
2) The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:
   a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
   b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
   c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
   d) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with recordkeeping requirements pursuant to §82.166. ("MVAC-like" appliance as defined at §82.152).
   e) Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156.
   f) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.
3) If the permittee manufactures, transforms, imports, or exports a class I or class II substance, the permittee is subject to all the requirements as specified in 40 CFR part 82, Subpart A, Production and Consumption Controls.
4) If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or system used on passenger buses using HCFC-22 refrigerant.

The permittee shall be allowed to switch from any ozone-depleting substance to any alternative that is listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR part 82, Subpart G, Significant New Alternatives Policy Program. *Federal Only - 40 CFR part 82*

**10 CSR 10-6.280 Compliance Monitoring Usage**

1) The permittee is not prohibited from using the following in addition to any specified compliance methods for the purpose of submission of compliance certificates:
   a) Monitoring methods outlined in 40 CFR Part 64;
   b) Monitoring method(s) approved for the permittee pursuant to 10 CSR 10-6.065, "Operating Permits", and incorporated into an operating permit; and
   c) Any other monitoring methods approved by the director.
2) Any credible evidence may be used for the purpose of establishing whether a permittee has violated or is in violation of any such plan or other applicable requirement. Information from the use of the following methods is presumptively credible evidence of whether a violation has occurred by a permittee:
   a) Monitoring methods outlined in 40 CFR Part 64;
   b) A monitoring method approved for the permittee pursuant to 10 CSR 10-6.065, "Operating Permits", and incorporated into an operating permit; and
   c) Compliance test methods specified in the rule cited as the authority for the emission limitations.
3) The following testing, monitoring or information gathering methods are presumptively credible testing, monitoring, or information gathering methods:
   a) Applicable monitoring or testing methods, cited in:
      i) 10 CSR 10-6.030, "Sampling Methods for Air Pollution Sources";
      ii) 10 CSR 10-6.040, "Reference Methods";
      iii) 10 CSR 10-6.070, "New Source Performance Standards";
      iv) 10 CSR 10-6.080, "Emission Standards for Hazardous Air Pollutants"; or
   b) Other testing, monitoring, or information gathering methods, if approved by the director, that produce information comparable to that produced by any method listed above.

# V. General Permit Requirements

The installation shall comply with each of the following requirements. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued,

**10 CSR 10-6.065(6)(C)1.B Permit Duration**

This permit is issued for a term of five years, commencing on the date of issuance. This permit will expire at the end of this period unless renewed.

**10 CSR 10-6.065(6)(C)1.C General Recordkeeping and Reporting Requirements**

1) Recordkeeping
   a) All required monitoring data and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report or application.
   b) Copies of all current operating and construction permits issued to this installation shall be kept on-site for as long as the permits are in effect. Copies of these permits shall be made immediately available to any Missouri Department of Natural Resources' personnel upon request.
2) Reporting
   a) All reports shall be submitted to the Air Pollution Control Program, Enforcement Section, P. O. Box 176, Jefferson City, MO 65102.
   b) The permittee shall submit a report of all required monitoring by:
      i) October 1st for monitoring which covers the January through June time period, and
      ii) April 1st for monitoring which covers the July through December time period.
      iii) Exception. Monitoring requirements which require reporting more frequently than semi annually shall report no later than 30 days after the end of the calendar quarter in which the measurements were taken.
   c) Each report shall identify any deviations from emission limitations, monitoring, recordkeeping, reporting, or any other requirements of the permit, this includes deviations or Part 64 exceedances.
   d) Submit supplemental reports as required or as needed. Supplemental reports are required no later than ten days after any exceedance of any applicable rule, regulation or other restriction. All reports of deviations shall identify the cause or probable cause of the deviations and any corrective actions or preventative measures taken.
      i) Notice of any deviation resulting from an emergency (or upset) condition as defined in paragraph (6)(C)7.A of 10 CSR 10-6.065 (Emergency Provisions) shall be submitted to the permitting authority either verbally or in writing within two working days after the date on which the emission limitation is exceeded due to the emergency, if the permittee wishes to assert an affirmative defense. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that indicate an emergency occurred and the permittee can identify the cause(s) of the emergency. The permitted installation must show that it was operated properly at the time and that during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or requirements in the permit. The notice must contain a description of the emergency, the steps taken to mitigate emissions, and the corrective actions taken.
      ii) Any deviation that poses an imminent and substantial danger to public health, safety or the environment shall be reported as soon as practicable.

iii) Any other deviations identified in the permit as requiring more frequent reporting than the permittee's semiannual report shall be reported on the schedule specified in this permit, and no later than ten days after any exceedance of any applicable rule, regulation, or other restriction.

e) Every report submitted shall be certified by the responsible official, except that, if a report of a deviation must be submitted within ten days after the deviation, the report may be submitted without a certification if the report is resubmitted with an appropriate certification within ten days after that, together with any corrected or supplemental information required concerning the deviation.

f) The permittee may request confidential treatment of information submitted in any report of deviation.

**10 CSR 10-6.065(6)(C)1.D Risk Management Plan Under Section 112(r)**

The permittee shall comply with the requirements of 40 CFR Part 68, Accidental Release Prevention Requirements. If the permittee has more than a threshold quantity of a regulated substance in process, as determined by 40 CFR Section 68.115, the permittee shall submit a Risk Management Plan in accordance with 40 CFR Part 68 no later than the latest of the following dates:

1) June 21, 1999;
2) Three years after the date on which a regulated substance is first listed under 40 CFR Section 68.130; or
3) The date on which a regulated substance is first present above a threshold quantity in a process.

**10 CSR 10-6.065(6)(C)1.F Severability Clause**

In the event of a successful challenge to any part of this permit, all uncontested permit conditions shall continue to be in force. All terms and conditions of this permit remain in effect pending any administrative or judicial challenge to any portion of the permit. If any provision of this permit is invalidated, the permittee shall comply with all other provisions of the permit.

**10 CSR 10-6.065(6)(C)1.G General Requirements**

1) The permittee must comply with all of the terms and conditions of this permit. Any noncompliance with a permit condition constitutes a violation and is grounds for enforcement action, permit termination, permit revocation and re-issuance, permit modification or denial of a permit renewal application.
2) The permittee may not use as a defense in an enforcement action that it would have been necessary for the permittee to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit
3) The permit may be modified, revoked, reopened, reissued or terminated for cause. Except as provided for minor permit modifications, the filing of an application or request for a permit modification, revocation and reissuance, or termination, or the filing of a notification of planned changes or anticipated noncompliance, does not stay any permit condition.
4) This permit does not convey any property rights of any sort, nor grant any exclusive privilege.
5) The permittee shall furnish to the Air Pollution Control Program, upon receipt of a written request and within a reasonable time, any information that the Air Pollution Control Program reasonably may require to determine whether cause exists for modifying, reopening, reissuing or revoking the permit or to determine compliance with the permit. Upon request, the permittee also shall furnish to the Air Pollution Control Program copies of records required to be kept by the permittee. The

permittee may make a claim of confidentiality for any information or records submitted pursuant to 10 CSR 10-6.065(6)(C)1.

**10 CSR 10-6.065(5)(C)1.H Incentive Programs Not Requiring Permit Revisions**

No permit revision will be required for any installation changes made under any approved economic incentive, marketable permit, emissions trading, or other similar programs or processes provided for in this permit.

**10 CSR 10-6.065(5)(C)1.I.C Reasonably Anticipated Operating Scenarios**

None.

**10 CSR 10-6.065(5)(C)1.I.E Title IV Allowances**

This permit shall prohibit emissions which exceed any allowances the installation holds under Title IV of the Clean Air Act.

1) No permit revisions shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program if the increases do not require a permit revision under any other applicable requirement.
2) Limits cannot be placed on the number of allowances that may be held by an installation. The installation may not use these allowances, however, as a defense for noncompliance with any other applicable requirement.
3) Any allowances held by a Title IV installation shall be accounted for according to procedures established in rules promulgated under Title IV of the Clean Air Act.
4) Aquila – Sibley Generating Station was issued a Title IV: Phase II Acid Rain Permit on February 9, 1998, with effective dates from January 1, 2000 through December 31, 2004. The Missouri Department of Natural Resources project number of this permit is EX095-0031-021 and its ORIS code is 2094. Aquila – Sibley Generating Station applied for a renewal of this permit on June 24, 2004 which reflected no change in the installation's status.

**10 CSR 10-6.065(6)(C)3 Compliance Requirements**

1) Any document (including reports) required to be submitted under this permit shall contain a certification signed by the responsible official.
2) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized officials of the Missouri Department of Natural Resources, or their authorized agents, to perform the following (subject to the installation's right to seek confidential treatment of information submitted to, or obtained by, the Air Pollution Control Program):
   a) Enter upon the premises where a permitted installation is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this permit;
   b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
   c) Inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
   d) As authorized by the Missouri Air Conservation Law, Chapter 643, RSMo or the Act, sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the terms of this permit, and all applicable requirements as outlined in this permit.

3) All progress reports required under an applicable schedule of compliance shall be submitted semiannually (or more frequently if specified in the applicable requirement). These progress reports shall contain the following:
   a) Dates for achieving the activities, milestones or compliance required in the schedule of compliance, and dates when these activities, milestones or compliance were achieved, and
   b) An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measures adopted.
4) The permittee shall submit an annual certification that it is in compliance with all of the federally enforceable terms and conditions contained in this permit, including emissions limitations, standards, or work practices. These certifications shall be submitted annually by April 1st, unless the applicable requirement specifies more frequent submission. These certifications shall be submitted to EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, as well as the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102. All deviations and Part 64 exceedances and excursions must be included in the compliance certifications. The compliance certification shall include the following:
   a) The identification of each term or condition of the permit that is the basis of the certification;
   b) The current compliance status, as shown by monitoring data and other information reasonably available to the installation;
   c) Whether compliance was continuous or intermittent;
   d) The method(s) used for determining the compliance status of the installation, both currently and over the reporting period; and
   e) Such other facts as the Air Pollution Control Program will require in order to determine the compliance status of this installation.

**10 CSR 10-6.065(6)(C)6 Permit Shield**

1) Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements as of the date that this permit is issued, provided that:
   a) The application requirements are included and specifically identified in this permit, or
   b) The permitting authority, in acting on the permit revision or permit application, determines in writing that other requirements, as specifically identified in the permit, are not applicable to the installation, and this permit expressly includes that determination or a concise summary of it.
2) Be aware that there are exceptions to this permit protection. The permit shield does not affect the following:
   a) The provisions of section 303 of the Act or section 643.090, RSMo concerning emergency orders,
   b) Liability for any violation of an applicable requirement which occurred prior to, or was existing at, the time of permit issuance,
   c) The applicable requirements of the acid rain program,
   d) The authority of the Environmental Protection Agency and the Air Pollution Control Program of the Missouri Department of Natural Resources to obtain information, or
   e) Any other permit or extra-permit provisions, terms or conditions expressly excluded from the permit shield provisions.

**10 CSR 10-6.065(6)(C)7 Emergency Provisions**

1) An emergency or upset as defined in 10 CSR 10-6.065(6)(C)7.A shall constitute an affirmative defense to an enforcement action brought for noncompliance with technology-based emissions

limitations. To establish an emergency- or upset-based defense, the permittee must demonstrate, through properly signed, contemporaneous operating logs or other relevant evidence, the following:

a) That an emergency or upset occurred and that the permittee can identify the source of the emergency or upset,
b) That the installation was being operated properly,
c) That the permittee took all reasonable steps to minimize emissions that exceeded technology-based emissions limitations or requirements in this permit, and
d) That the permittee submitted notice of the emergency to the Air Pollution Control Program within two working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and any corrective actions taken.

2) Be aware that an emergency or upset shall not include noncompliance caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

**10 CSR 10-6.065(6)(C)8 Operational Flexibility**

An installation that has been issued a Part 70 operating permit is not required to apply for or obtain a permit revision in order to make any of the changes to the permitted installation described below if the changes are not Title I modifications, the changes do not cause emissions to exceed emissions allowable under the permit, and the changes do not result in the emission of any air contaminant not previously emitted. The permittee shall notify the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as well as EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, at least seven days in advance of these changes, except as allowed for emergency or upset conditions. Emissions allowable under the permit means a federally enforceable permit term or condition determined at issuance to be required by an applicable requirement that establishes an emissions limit (including a work practice standard) or a federally enforceable emissions cap that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject.

1) Section 502(b)(10) changes. Changes that, under section 502(b)(10) of the Act, contravene an express permit term may be made without a permit revision, except for changes that would violate applicable requirements of the Act or contravene federally enforceable monitoring (including test methods), recordkeeping, reporting or compliance requirements of the permit.
   a) Before making a change under this provision, The permittee shall provide advance written notice to the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as well as EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, describing the changes to be made, the date on which the change will occur, and any changes in emission and any permit terms and conditions that are affected. The permittee shall maintain a copy of the notice with the permit, and the APCP shall place a copy with the permit in the public file. Written notice shall be provided to the EPA and the APCP as above at least seven days before the change is to be made. If less than seven days notice is provided because of a need to respond more quickly to these unanticipated conditions, the permittee shall provide notice to the EPA and the APCP as soon as possible after learning of the need to make the change.
   b) The permit shield shall not apply to these changes.

**10 CSR 10-6.065(6)(C)9 Off-Permit Changes**

1) Except as noted below, the permittee may make any change in its permitted operations, activities or emissions that is not addressed in, constrained by or prohibited by this permit without obtaining a permit revision. Insignificant activities listed in the application, but not otherwise addressed in or

prohibited by this permit, shall not be considered to be constrained by this permit for purposes of the off-permit provisions of this section. Off-permit changes shall be subject to the following requirements and restrictions:

a) The change must meet all applicable requirements of the Act and may not violate any existing permit term or condition; the permittee may not change a permitted installation without a permit revision if this change is subject to any requirements under Title IV of the Act or is a Title I modification;
b) The permittee must provide written notice of the change to the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as well as EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, no later than the next annual emissions report. This notice shall not be required for changes that are insignificant activities under 10 CSR 10-6.065(6)(B)3. This written notice shall describe each change, including the date, any change in emissions, pollutants emitted and any applicable requirement that would apply as a result of the change.
c) The permittee shall keep a record describing all changes made at the installation that result in emissions of a regulated air pollutant subject to an applicable requirement and the emissions resulting from these changes; and
d) The permit shield shall not apply to these changes.

**10 CSR 10-6.020(2)(R)12 Responsible Official**

"The application utilized in the preparation of this permit was signed by Glenn P. Keefe, Operating Vice President, Missouri Electric. On February 7, 2006, the Air Pollution Control Program was informed that Scott Heidtbrink, Vice President, Generation and Energy Resources is now the responsible official. If this person terminates employment, or is reassigned different duties such that a different person becomes the responsible person to represent and bind the installation in environmental permitting affairs, the owner or operator of this air contaminant source shall notify the Director of the Air Pollution Control Program of the change. Said notification shall be in writing and shall be submitted within 30 days of the change. The notification shall include the name and title of the new person assigned by the source owner or operator to represent and bind the installation in environmental permitting affairs. All representations, agreement to terms and conditions and covenants made by the former responsible person that were used in the establishment of limiting permit conditions on this permit will continue to be binding on the installation until such time that a revision to this permit is obtained that would change said representations, agreements and covenants.

**10 CSR 10-6.065(6)(E)6 Reopening-Permit for Cause**

This permit may be reopened for cause if:

1) The Missouri Department of Natural Resources (MDNR) receives notice from the Environmental Protection Agency (EPA) that a petition for disapproval of a permit pursuant to 40 CFR § 70.8(d) has been granted, provided that the reopening may be stayed pending judicial review of that determination,
2) MDNR or EPA determines that the permit contains a material mistake or that inaccurate statements were made which resulted in establishing the emissions limitation standards or other terms of the permit,
3) Additional applicable requirements under the Act become applicable to the installation; however, reopening on this ground is not required if—:
   a) The permit has a remaining term of less than three years;

b) The effective date of the requirement is later than the date on which the permit is due to expire; or
c) The additional applicable requirements are implemented in a general permit that is applicable to the installation and the installation receives authorization for coverage under that general permit,

4) The installation is an affected source under the acid rain program and additional requirements (including excess emissions requirements), become applicable to that source, provided that, upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into the permit; or
5) MDNR or EPA determines that the permit must be reopened and revised to assure compliance with applicable requirements.

**10 CSR 10-6.065(6)(E)1.C Statement of Basis**

This permit is accompanied by a statement setting forth the legal and factual basis for the draft permit conditions (including references to applicable statutory or regulatory provisions). This Statement of Basis, while referenced by the permit, is not an actual part of the permit.

# VI. Attachments

Attachments follow.

# ATTACHMENT A

## Method 22 (Outdoor) Observation Log

This recordkeeping sheet or an equivalent form may be used for the recordkeeping requirements of 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants.*

| Method 22 Opacity Emission Observations | | | |
|---|---|---|---|
| Date | Method 22 Test Observer | Visible Emissions (yes/no) | If visible emissions, was a Method 9 done? (yes/no) |
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# ATTACHMENT B

## Inspection/Maintenance/Repair/Malfunction Log

This recordkeeping sheet or an equivalent form may be used to record inspections of equipment, maintenance, repairs and malfunctions.

| Inspection/Maintenance/Repair/Malfunction Log | | |
|---|---|---|
| Date | Emission Unit/Equipment | Activities Performed |
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# ATTACHMENT C

## Method 9 Opacity Emissions Observations

This recordkeeping sheet or an equivalent form may be used for the recordkeeping requirements of 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants.*

| Method 9 Opacity Emissions Observations | |
|---|---|
| Company | Observer |
| Location | Observer Certification Date |
| Date | Emission Unit |
| Time | Control Device |

| Hour | Minute | Seconds | | | | Steam Plume (check if applicable) | | Comments |
|---|---|---|---|---|---|---|---|---|
| | | 0 | 15 | 30 | 45 | Attached | Detached | |
| | 0 | | | | | | | |
| | 1 | | | | | | | |
| | 2 | | | | | | | |
| | 3 | | | | | | | |
| | 4 | | | | | | | |
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| | 15 | | | | | | | |
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| | 17 | | | | | | | |
| | 18 | | | | | | | |

| SUMMARY OF AVERAGE OPACITY | | | | |
|---|---|---|---|---|
| Set Number | Time | | Opacity | |
| | Start | End | Sum | Average |
| | | | | |
| | | | | |
| | | | | |

Readings ranged from _____ to _____ % opacity.

Was the emission unit in compliance at the time of evaluation? _____ YES _____ NO _____ Signature of Observer

# ATTACHMENT D
## VOC Compliance Form

This recordkeeping sheet or an equivalent form may be used for the recordkeeping requirements of Permit Condition (EU0120 and EU0130)-001, which is based on Construction Permit #0897-025.

| Material Used | 1<br>Amount of Material Used (gal or lb) | 2<br>Material Density (lb/gal) | 3<br>VOC Content (lb/gal) | 4<br>VOC Weight Percent (%) | 5<br>VOC Emissions (Tons) |
|---|---|---|---|---|---|
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| | | | | Total VOC Emissions This Month (tons) | |
| | | | | 12-MonthTotal of VOC Emissions (tons/yr) | |

If Column 1 is in gallons, then Column 5 = Column 1 X Column 3 X 0.0005
If Column 1 is in pounds, then Column 5 = Column 1 X (Column 4 ÷ 100) X 0.0005
<u>or</u> Column 5 = (Column 1 ÷ Column 2) X Column 3 X 0.0005
Note: A 12-Month Total of VOC Emissions less than or equal to 12.0 tons/yr indicates compliance.

# ATTACHMENT E

## 10 CSR 10-6.260 Compliance Demonstration

This attachment may be used to demonstrate that EU0090 through EU0110 are always in compliance with 10 CSR 10-6.260, *Restriction of Emission of Sulfur Compounds*, and that EU0080 is always in compliance with this rule when it is burning fuel with a sulfur content of 1.5% by weight or less.

General Equation

ppmv $SO_2$ = $SO_2$ Emission Factor in lb/MMBtu X F Factor in MMBtu/wscf X Conversion Factor for lb/scf to ppm X Conversion Factor for ppmw to ppmv

1) $SO_2$ emission factor for gasoline engines < 600 HP = 0.084 lb/MMBtu. (From **AP-42 Table 3.3-1**)
   $SO_2$ emission factor for diesel engines < 600 HP = 0.29 lb/MMBtu (From same table)
   $SO_2$ emission factor for diesel engines > 600 hp = 1.01 X % sulfur in lb/MMBtu = 1.01 X 1.5 lb/MMBtu = 1.52 lb/MMBtu (EPA AP-42 Table 3.4-1)

2) The F factor is the ratio of gas volume of products of combustion to the heat content of the fuel. For fuel oil the F factor = 1 MMBtu / 10,320 wscf (From Part 60 Appendix A Method 19 Table 19-2)

3) Conversion factor for lb/scf to ppm = ppm / 1.660E-7 lb/scf (From Part 60 Appendix A Method 19 Table 19-1)

4) Conversion factor for ppmw to ppmv = (28.8 / Molecular Weight of $SO_2$) ppmv / 1 ppmw = (28.8/64) ppmv / ppmw= 0.45 ppmv / ppmw (From **AP-42 Appendix A**)

Compliance Demonstration for EU0090 and EU0100 Welding Machines

$$ppmv\ SO_2 = \left(0.084\ lb/MMBtu\right)\left(MMBtu/10{,}320\ ft^3\right)\left(ppmw/1.667E^{-7}\ lb/scf\right)\left(0.45\ ppmv/ppmw\right) = 2\ ppmv$$

22 ppmv $SO_2$ << 500 ppmv $SO_2$, so EU0090 and EU0100 are always in compliance

Compliance Demonstration for EU0110 Back-up Diesel Fire Pump

$$ppmv\ SO_2 = \left(0.29\ lb/MMBtu\right)\left(MMBtu/10{,}320\ ft^3\right)\left(ppmw/1.667E^{-7}\ lb/scf\right)\left(0.45\ ppmv/ppmw\right) = 76\ ppmv$$

76 ppmv $SO_2$ << 500 ppmv $SO_2$, so EU0110 is always in compliance

Compliance Demonstration for EU080 Emergency Generator Burning 1.5% Sulfur Fuel

$$ppmv\ SO_2 = \left(1.52\ lb/MMBtu\right)\left(MMBtu/10{,}320\ ft^3\right)\left(ppmw/1.667E^{-7}\ lb/scf\right)\left(0.45\ ppmv/ppmw\right) = 398\ ppmv$$

398 ppmv $SO_2$ << 2000 ppmv $SO_2$, so EU0080 is always in compliance when burning fuel with a sulfur content of 1.5% by weight or less.

# STATEMENT OF BASIS

**Permit Reference Documents**
These documents were relied upon in the preparation of the operating permit. Because they are not incorporated by reference, they are not an official part of the operating permit.

1) Part 70 Renewal Operating Permit Application, received 09/08/03;
2) 2004 Emissions Inventory Questionnaire, received 03/24/05;
3) U.S. EPA document AP-42, *Compilation of Air Pollutant Emission Factors*; Volume I, Stationary Point and Area Sources, Fifth Edition.

**History and Notes on Emission Units Without Limitations**

1) Coal unloading (EP-01) and coal storage pile (EP-02) are fugitive sources, which do not emit regulated pollutants from a discrete stack or vent. They emit particulate matter directly into the ambient air, and do not have any type of capture/control devices. They are not subject to any specific rule except the installation wide requirement of 10 CSR 10-6.170, *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin.* (See items 4 and 5 in Other Regulatory Determinations below.)

2) Portable space heaters (EP-17) are not subject to any specific rule.

3) Storage tanks for volatile organic liquids are not subject to any specific rule. (See items 2 and 3 in NSPS Applicability below, and item 2 in Other Regulatory Determinations below.)

**Applicable Requirements Included in the Operating Permit but Not in the Application or Previous Operating Permits**
In the operating permit application, the installation indicated they were not subject to the following regulation(s). However, in the review of the application, the agency has determined that the installation is subject to the following regulation(s) for the reasons stated.

None.

**Other Air Regulations Determined Not to Apply to the Operating Permit**
The Air Pollution Control Program (APCP) has determined that the following requirements are not applicable to this installation at this time for the reasons stated.

1) 10 CSR 10-2.230, *Control of Emissions from Industrial Surface Coating*
EU0130, Spray Paint Booth, is not subject to this rule. Per 10 CSR 10-2.230(1)(B), it is exempt because it has an allowable VOC emission limit established under 10 CSR 10-6.060 *Construction Permits Required* (Construction Permit #0897-025 issued 8/4/1997.) This rule does not apply to any other units at this installation.

2) 10 CSR 10-2.260, *Control of Petroleum Liquid Storage, Loading and Transfer*
This rule applies to petroleum liquid storage tanks with capacities greater than 40,000 gallons. There are no storage vessels with capacities greater than 40,000 gallons at this facility; therefore this rule is not applicable.

3) 10 CSR 10-6.100, *Alternate Emission Limits*
This rule is not applicable because the installation is in an ozone attainment area.

4) 10 CSR 10-6.360, *Control of NOx Emissions From Electric Generating Units and Non- Electric Generating Boilers*
EU0050 through EU0070, the boilers, are not subject to this rule because, per §(1)(A), it does not apply to electric generating units in Jackson County. This rule does not apply to any other units at this installation.

5) 10 CSR 10-6.400, *Restriction of Emission of Particulate Matter from Industrial Processes*
The following emission units are not subject to this rule because, per §(1)(B)7, it does not apply to fugitive emissions.
Coal unloading (EP-01)
Coal storage piles (EP-02)
The following emission units are not subject to this rule because, per §(1)(B)12, it does not apply to the grinding, crushing and conveying operations at a power plant. (Note: This rule was mistakenly listed as applicable to EU0030, Coal Crusher House, on the permit application.)
EU0010 Coal Conveyor # 18
EU0020 Coal Handling System (Except for Conveyor #18)
EU0030 Coal Crusher House
EU0040 Fly Ash Handling System
The following emission units are not subject to this rule because, per §(1)(B)6, it does not apply to the burning of fuel for indirect heating.
EU0050 Boiler #1
EU0060 Boiler #2
EU0070 Boiler #3
The following emission units are not subject to this rule because, per §(2)(A), liquids and gases used solely as fuels for purposes of combustion are excluded from the definition of process weight.
EU0080 Emergency Generator
EU0090 and EU0100 Welding Machines
EU0110 Back-Up Fire Pump Engine
The following emission unit is not subject to this rule because, per §(1)(B)11, its potential to emit is less than 0.5 lb/hr. (It is a small, facility maintenance only paint booth. The construction permit for it, 0897-025, calculated its annual potential to emit as 100 pounds.) .
EU0130 Spray Paint Booth

**Construction Permit Revisions**
The following revisions were made to construction permits for this installation:

1) Construction Permit 0393-004
   a) This permit listed 10 CSR 10-2.060, *Restriction of Emission of Visible Air Contaminants,* as an applicable rule. This rule was rescinded on May 30, 2000, and replaced by 10 CSR 10-6.220.
   b) This permit did not include 40 CFR Part 60 Subpart Y, *Standards of Performance for Coal Preparation Plants,* as an applicable rule. However, this rule is applicable to EU0010 Coal Conveyor #18 because this unit was constructed after October 24, 1974 and is used to transport coal to the EU0030 Coal Crusher House.

**NSPS Applicability**

1) 40 CFR Part 60 Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*
   40 CFR Part 60 Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*
   40 CFR Part 60 Subpart Db, *Standards of Performance for Industrial, Commercial, Institutional Steam Generating Units for Which Construction is Commenced After June 19, 1984*
   These subparts do not apply to this installation because the boilers were constructed prior to the subparts' applicability dates.

2) 40 CFR Part 60 Subpart K, *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978*
   40 CFR Part 60 Subpart Ka, *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984*
   These subparts apply to storage vessels with capacities greater than 40,000 gallons that are used to store petroleum liquids. There are no storage vessels with capacities greater than 40,000 gallons at this facility; therefore these subparts are not applicable.

3) 40 CFR Part 60 Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*
   This subpart applies to storage vessels with capacities greater than or equal to 75 $m^3$ (about 19,800 gallons) that are used to store volatile organic liquids and were constructed after July 23, 1984. There are no storage vessels with capacities greater than or equal to 19,800 gallons that were constructed after July 23, 1984 at this facility; therefore this subpart is not applicable.

4) 40 CFR Part 60 Subpart Y, *Standards of Performance for Coal Preparation Plants*
   This subpart applies to thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems constructed after October 24, 1974.

a) EU0010 Coal Conveyor #18 is subject to the requirements of Subpart Y because this unit was constructed after October 24, 1974 and is used to transport coal to the EU0030 Coal Crusher House.
b) EU0020 Coal Handling System (Except for Conveyor #18) and EU0030 Coal Crusher House were constructed prior to October 24, 1974, and therefore are not subject to the requirements of Subpart Y.
c) Conveyor #16 and Conveyor #17 were constructed after October 24, 1974. However, these units only convey coal to a coal storage pile. They do not meet the definition of coal conveying equipment (i.e. equipment used to convey coal to or remove coal and refuse from coal processing machinery). Therefore, these units are not subject to the requirements of Subpart Y.

No other New Source Performance Standards apply to this installation.

**MACT Applicability**

1) 40 CFR Part 63, Subpart T, *National Emission Standards for Halogenated Solvent Cleaning*
This subpart does not apply to the Parts Washer and the Spray Paint Booth (EU0120 and EU0130) because the facility does not use any cleaning solvents in the list of applicable solvents for subpart T.

2) 40 CFR Part 63 Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters*
This subpart does not apply to the boilers (EU0050 through EU0070) because they are fossil fuel-fired combustion units of more than 25 megawatts that serve as generators that produce electricity for sale.

3) 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*
This subpart does not apply to EU0080, Emergency Generator because this internal combustion engine's MHDR is less than 500 brake horsepower.

4) 40 CFR Part 63 Subpart UUUUU, *National Emission Standards for Coal- and Oil- Fired Electric Utility Steam Generating Units*
Coal- and oil- fired electric utility steam generating units were removed from the section 112(c) list of regulated source categories on March 29, 2005.

No other Maximum Achievable Control Technology standards apply to this installation.

**NESHAP Applicability**
In the permit application and according to APCP records, there was no indication that any Missouri Air Conservation Law, Asbestos Abatement, 643.225 through 643.250; 10 CSR 10-6.080, Emission Standards for Hazardous Air Pollutants, Subpart M, National Standards for Asbestos; and 10 CSR 10-6.250, Asbestos Abatement Projects - Certification, Accreditation, and Business Exemption Requirements apply to this installation. The installation is subject to these regulations if they undertake any projects that deal with or involve any asbestos containing materials. None of the installation's operating projects underway at the time of this review deal with or involve asbestos containing material. Therefore, the above regulations were not cited in the operating permit. If the installation should undertake any construction or demolition projects in the future that deal with or involve any asbestos

containing materials, the installation must follow all of the applicable requirements of the above rules related to that specific project.

No other National Emission Standards for Hazardous Air Pollutants (NESHAPs) apply to this installation.

**CAM Applicability**
40 CFR Part 64, *Compliance Assurance Monitoring (CAM)*
The boilers (EU0050 through EU0070) meet the applicability criteria for this part because these units each have the uncontrolled potential to emit particulate matter above the major source threshold levels (as defined by Part 70) and utilize control devices (as defined by 40 CFR §64.1) to comply with 10 CSR 10-2.040.

The permittee submitted original and modified CAM Plans, CAM Test Plans, and CAM Quality Assurance/Quality Control (QA/QC) Plans at various times. The latest versions of each approved by the Missouri Department of Natural Resources. Air Pollution Control Program, Compliance and Enforcement Section, were submitted August 1, 2006, August 16, 2006, and July 28, 2006, respectively. Copies of these are at the end of this Statement of Basis.

This accepted Compliance Assurance Monitoring has been incorporated into Permit Condition (EU0050-through EU0070)-001.

Where conflicts arise between 40 CFR Part 60 and the approved CAM plan, CAM test plan, and CAM QA/QC plan and 40 CFR Part 60, the CAM plan, CAM test plan and CAM QA/QC plan govern. This will assure that where there is doubt, the acceptance criteria in these approved documents will be used, and not those in 40 CFR Part 60 Appendix B Performance Specification 11 (PS-11). These monitors are indicators of compliance, and not compliance monitors. The full PS-11 requirements do not apply to monitors that are only indicators of compliance.

**Other Regulatory Determinations**

1) 10 CSR 10-2.210, *Control of Emissions from Solvent Metal Cleaning*
   EU0120, Parts Washer, and EU0130, Spray Paint Booth, are subject to this rule, per 10 CSR 10-2.210(1).

2) 10 CSR 10-6.220, *Restriction of Emissions of Visible Air Contaminants*
   The following emission units are not subject to this rule because, per §(1)(A), it does not apply to internal combustion engines.
   EU0080 Emergency Generator
   EU0090 and EU0100 Welding Machines
   EU0110 Back-Up Fire Pump Engine
   This rule is not applied to EU0010 Coal Conveyor #18 because the opacity limitation is superseded by the more stringent limitation in 40 CFR Part 60 Subpart Y. 10 CSR 10-6.220 allows an exception of 60% opacity for no more than 6 minutes in any 60 minutes. Subpart Y provides no exception to the opacity limitation.

3) 10 CSR 10-6.260, *Restriction of Emissions of Sulfur Compounds*
This regulation does not apply to the following emission units, because the only significant emission from coal unloading, storage, crushing, or screening is particulate matter. (See 11.9 Western Surface Coal Mining and 11.10 Coal Cleaning in AP-42.)
EU0010 Conveyor #18
EU0020 Coal Handling System (Except for Conveyor #18)
EU0030 Coal Crusher House
Coal storage piles
Coal crusher (inoperable)
This regulation does not apply to the following emission unit, because the only significant emission from fly ash handling is particulate matter. (See 1.1 and 1.2 Coal Combustion in AP-42.)
EU0040 Fly Ash Handling

**Other Regulations Not Cited in the Operating Permit or the Above Statement of Basis**
Any regulation which is not specifically listed in either the Operating Permit or in the above Statement of Basis does not appear, based on this review, to be an applicable requirement for this installation for one or more of the following reasons:
1) The specific pollutant regulated by that rule is not emitted by the installation;
2) The installation is not in the source category regulated by that rule;
3) The installation is not in the county or specific area that is regulated under the authority of that rule;
4) The installation does not contain the type of emission unit which is regulated by that rule;
5) The rule is only for administrative purposes.

Should a later determination conclude that the installation is subject to one or more of the regulations cited in this Statement of Basis or other regulations which were not cited, the installation shall determine and demonstrate, to the APCP's satisfaction, the installation's compliance with that regulation(s). If the installation is not in compliance with a regulation which was not previously cited, the installation shall submit to the APCP a schedule for achieving compliance for that regulation(s).

**Copy of Compliance Assurance Monitoring (CAM) Documents**
The following forty-two pages contain four CAM-related attachments:
1) The approved eight-page CAM Plan for the Aquila - Sibley Generating Station submitted, August 1, 2006 (although still dated December 23, 2004 internally); [SB-7 through SB-14]
2) Sixteen pages (all but the Appendix B) of the approved CAM Test Plan for the Aquila – Sibley Generating Station, submitted August 16, 2006; and [SB-15 through SB-30]
3) Eighteen pages (all but the appendices) of the CAM Quality Assurance and Quality Control Plan for the Particulate Matter Continuous Emissions Monitoring Systems for the Aquila – Sibley Generating Station, submitted July 28, 2006. [SB-31 through SB-48]

## COMPLIANCE ASSURANCE MONITORING PLAN
### Aquila – Sibley Generating Station

A. Background

1. Emissions Unit:

| | |
|---|---|
| Description: | Boiler #1 – Babcock & Wilcox Cyclone, 609.6 MMBtu/hr<br>Boiler #2 – Babcock & Wilcox Cyclone, 627.3 MMBtu/hr<br>Boiler #3 – Babcock & Wilcox Cyclone, 4094.1 MMBtu/hr<br>(All 3 Units exhaust through Common Stack) |
| Facility: | Sibley Generating Station<br>33200 E. Johnson Road<br>Sibley, MO 64088 |

2. Applicable Requirement:

| | |
|---|---|
| Regulation: | 10 CSR 10-2.040, *Maximum Allowable Emission of Particulate Matter From Fuel Burning Equipment Used For Indirect Heating* |
| Pollutants: | Particulate Matter ("PM") |
| Emission Limits: | 0.12 lb PM per MMBtu for each Boiler |
| Monitoring Requirements: | Per 10 CSR 10-2.040: None.<br>Per Operating Permit: Current gap-filling compliance demonstration method is a calculation based on coal throughput and emission factor.<br>Per Proposed CAM: A Teledyne Analytical Instruments (TAI) Laserhawk 360 particulate monitor installed in the common stack to serve as an indicator of precipitator performance. |

3. Control Technology: Electrostatic precipitator (ESP)

B. Monitoring Approach

The key elements of the monitoring approach are presented in Table 1. The CAM performance indicator is a continuous Particulate Monitor, Model Laserhawk 360 ("CEMS"), manufactured by Teledyne Analytical Instruments. The Monitor output will be used to provide a reasonable level of compliance assurance by indicating ESP performance. The CEMS readings shall not be used to directly demonstrate compliance with 10 CSR 10-2.040 limits.

**COMPLIANCE ASSURANCE MONITORING PLAN**
**Aquila – Sibley Generating Station**

TABLE 1. MONITORING APPROACH

| | |
|---|---|
| I. Indicator | Particulate Level of common stack exhaust, as measured by the output of a Continuous PM Monitor, TAI Model Laserhawk 360. The monitor output will be recorded in units of pounds PM per cubic feet or pounds PM per megawatt. Correlation between the monitor output and a Reference Method will be established during a performance test. |
| Measurement Approach | PM CEMS in common stack exhaust. When the hourly average PM CEMS reading reaches or exceeds a value equivalent to 1.25 times the highest PM CEMS response value reached during the correlation tests, or 0.9 times the source emissions limit (an "Excursion"), then corrective action must be taken to bring the Unit back within these Limits (see Section 4 below). |
| II. Indicator Range | The Particulate Monitor indicator range is an hourly average reading covering the full range of measurements made during the initial calibration plus 25% (minimum). The indicator range is a calibrated instrument output that offers reasonable assurance of compliance with the PM emissions limit. An Excursion (defined above and in Section 4) triggers corrective action. |
| III. Performance Criteria<br>A. Data Representativeness | The PM CEMS is installed at a location in the common stack, chosen to minimize problems due to flow disturbances or varying PM stratification. Prior to installation, measurements shall be made of flow dynamics and/or particulate matter to determine the existence or extent of PM stratification. |
| B. Verification of Operational Status | Initial correlation tests will be conducted as specified in this document, with a minimum of 12 valid test runs at 2 different PM concentration levels. The results of these tests will be used to determine the correlation equation and correlation coefficient. See Section C.3.b. below for definition of "valid" test run. |
| C. QA/QC Practices and Criteria | Daily Zero and Span checks will be made, and the results documented. The instrument will be recalibrated if the Zero or Span value exceeds ±5% of the reference value. In addition, quarterly Reference Calibrations, routine and recommended periodic maintenance procedures will be performed in accordance with the Manufacturer's instructions. |
| D. Monitoring Frequency | The PM concentration of the common stack is monitored continuously. |
| E. Data Collection Procedures | The DAS retains all hourly average PM concentration data, plus all daily Zero-Span calibrations. Alarms will signal an instrument malfunction or Excursion. |
| F. Averaging period | One minute average PM concentration data are used to calculate hourly block averages. |

C. Monitoring Approach Justification

1. Background

The pollutant-specific emission units (PSEU) are three cyclone-fired boilers that route exhaust to a common stack and have a combined heat input rating above 5,000 MMBtu/hr. Each boiler has a dedicated ESP, which controls particulate emissions. All three boilers were constructed before February 15, 1979, and are therefore considered "Existing" per 10 CSR 10-2.040.

**COMPLIANCE ASSURANCE MONITORING PLAN**
**Aquila – Sibley Generating Station**

2. Rationale for Selection of Performance Indicators

The CAM indicator selected is an "In-Situ" Particulate Matter CEMS based on light scattering principles. Model Laserhawk 360, manufactured by Teledyne Analytical Instruments. The rationale for the choice of this specific approach is as follows:

a) Continuous PM monitors are widely used to measure and report PM emissions in many parts of the world, and are considered to be the best real-time indicators of actual mass concentrations.

b) Rather than using a COMS as a precursor to further action (i. e. calculation of PM emissions via TAI model evaluation) the continuous PM monitor output can directly trigger the need for corrective action and/or reporting obligations.

c) The TAI instrument has been used as both a performance and regulatory monitor in a wide variety of applications, with more than 600 field installations.

d) The TAI instrument has a good record for reliability and low maintenance.

e) The TAI instrument has been used in a number of officially sponsored test programs, and has met preliminary PS-11 specifications in two of them.[1,2]

f) The TAI instrument is compatible with the existing DAHS system, which can readily be set up to record the appropriate averages, calibrations and signals for instrument malfunction or PM exceedances.

**COMPLIANCE ASSURANCE MONITORING PLAN**
**Aquila – Sibley Generating Station**

3. Instrument Calibration

a) *General and Pre-Test Monitoring Period.* The instrument will be calibrated based on the boiler load, coal, ESP characteristics and any other performance or test data deemed applicable. Reference method measurements will be conducted in accordance with accepted method standards (normally EPA Methods 5 or 17) and compared with the integrated (arithmetic average) PM CEMS output over the reference method test period as described below.

The Laserhawk 360 will be installed at a vertical stack location recommended by Aquila. From a practical perspective, this would be a location with existing platforming, access and power. The Monitor will be initially operated for a period of approximately 30 days under various operating conditions to identify conditions necessary to produce the two target concentration levels for the correlation testing (see below). During the 30-day pre-test monitoring period, the following key operating parameters will be recorded:

A. Monitor Output
B. Plant Load
C. Fuel Type
D. ESP Voltage and Current Readings

b) *Correlation/Performance Testing.* A minimum of twelve (12) valid runs (e.g. 2 loads, 2 fuel blends and 3 tests per condition) will be required to obtain the correlation equation and correlation coefficient. A run will be declared "not valid" only when performed during a time when conditions are clearly not representative of normal operations. The correlation will be determined according to equation 11-3 of PS-11, and the correlation coefficient will be calculated according to equation 11-14 of the referenced document[3].

c) Tests should be performed at two (2) different PM concentration levels, with a minimum of three (3) tests at each level, if possible. Level 1 encompasses the range from 0 to 50% of the maximum PM concentration available. Level 2 should range from 75% to 100% of the maximum concentration. The source should be operated over the complete range of expected conditions, so as to assure

that the data produced is representative. The data gathered during the 30-day pre-test monitoring period (see Section 3.A above) shall be used to produce the desired concentrations for the test runs. The Sibley Generating Station anticipates operating with a fuel mix of 70% - 100% sub-bituminous coal (such as PRB), 0-30% bituminous, and approximately 1% tire-derived fuel (TDF). The attached coal crush sizing chart provides rough values as recommended by Babcock and Wilcox . Heating values range from 8,350 to 12,500 btu/lb.

d) During correlation testing, the reference method data and PM CEMS measurements will be converted into units of pounds PM per MMBtu to establish limits comparable to the regulatory standard (0.12 lbs/MMBtu). Once established, these limits will be converted into units of pounds PM per actual stack gas volume, or pounds of PM per megawatt. During operation after testing, the CEMS output, and determination of PM levels with respect to limits, will be conducted only in units of pounds per actual stack gas volume or pounds PM per megawatt.

e) The correlation coefficient (r) resulting from the calibration testing must be $\geq .75$.

f) Once the correlation equation has been determined, it will be applied to PM CEMS data collected by the Data Recorder.

g) Based on the results of the reference method measurements, the data will be documented in a manner similar to that shown in Table 2, and plotted as shown in Figure 1. The point at which an alarm occurs, as well as a reporting requirement and corrective action, will be determined when the hourly average of the PM CEMS output reaches the **lower** of the following limits:

   i. A value equivalent to 1.25 times the highest PM CEMS response value reached during the correlation tests.
   ii. A value equivalent to 0.9 times the source emissions limit.

4. <u>Inspection/Corrective Action</u>

In the event of an Excursion (1-hour CEMS reading indicative of 1.25 times the highest PM CEMS response value reached during the correlation tests, or 0.9 times the source emissions limit. Aquila will take steps to identify and correct any

operational conditions that may be contributing to the Excursion. The operational checks will be made as soon as practicable and may include

- ESP field checks (T/R voltage, current, spark rate)
- Visual Inspection of Control Equipment
- Unusual Fuel Characteristics
- Boiler Upset Condition

5. QA/QC Criteria

Factory supplied filter standards will be used to calibrate the instrument at a reference Zero and upscale Span value. These calibration standards will be maintained in accordance with manufacturer's recommendations. Following this calibration, an internal "Zero-Span" cycle will be initiated, thus establishing initial values for future reference. Daily "Zero-Span" cycles will follow, with the results stored in the data system and compared with the initial values. Should either the "Zero" or Span" value error exceed ± 5% of the starting value, an alarm will be initiated to signal the need for recalibration of the instrument to the factory standards. In addition, a quarterly reference calibration will be performed as described in the instrument operations manual. The factory standards will be used to measure instrument response at a Zero and Upscale value. Should either of these readings exceed the factory standard by more than ± 5% of the full scale measurement range, the instrument will be reset to the factory standard values. Finally, routine and scheduled maintenance procedures will be established in accordance with manufacturer's recommendations.

6. Data Acquisition Needs

The data system will be set up to perform the following tasks:

a) Record the Analog output of the PM CEMS.
b) Calculate emissions values, in the units of the required standard, and according to the correlation(s) established during the PM CEMS calibration.
c) Store the hourly averages of the calculated emissions values.

d) Record the daily "Zero-Span" calibration results.

e) Initiate an alarm if any daily Zero or Span value exceeds the error limit of ± 5%.

f) Initiate an alarm if the hourly averaged PM CEMS emission value reaches or exceeds the limit value, as defined in section 3, above.

g) Initiate an alarm on the occurrence of a malfunction status indicator from the Laserhawk 360.

## References

iii. *Notice of Data Availability and Request for Comments*, **FRL-5941-4, Federal Register, Vol. 2, No.249 (December 30, 1997).**

2. *Results of Continuous PM Monitor Testing at Pleasant Prairie Power Plant*, **Ralph L Roberson, Jon Konings and Charles E. Dene, EPRI CEM Users Group Meeting, May 16-18, 2001, Charlotte, NC.**

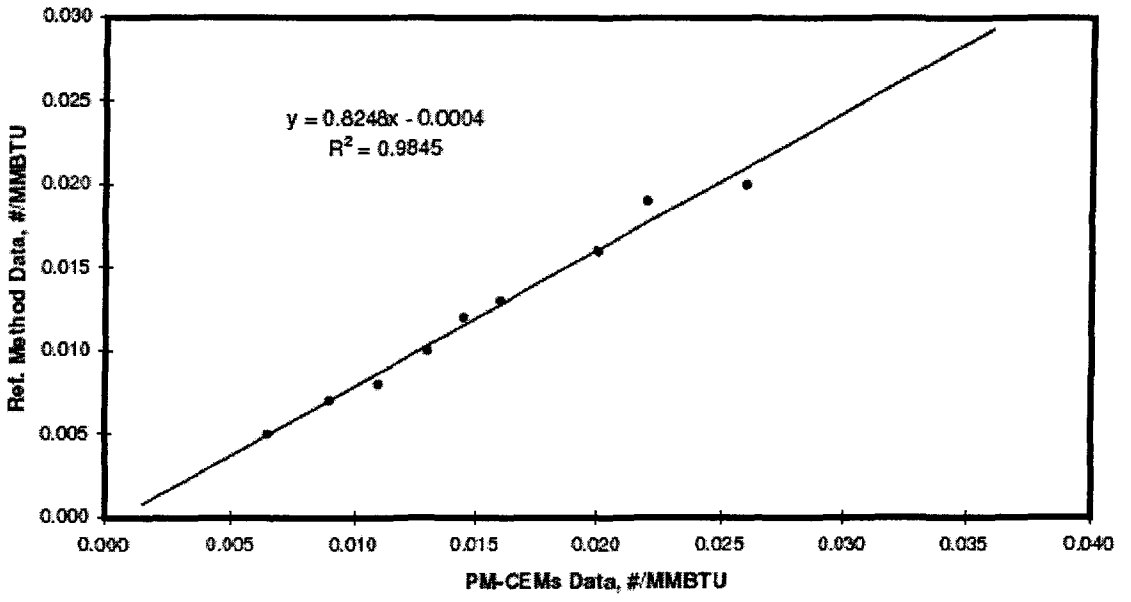
3. *40 CFR 60, Appendix B, Performance Specification 11 – Specification and Test Procedure for Particulate Matter Continuous Monitoring Systems at Stationary Sources.*

**COMPLIANCE ASSURANCE MONITORING PLAN**
**Aquila – Sibley Generating Station**

**Table 2.**

| Date | Run # | PM Level | Reference Method Data | PM CEMS Data |
|---|---|---|---|---|
| | 1 | 1 | 0.0050 | 0.0065 |
| | 2 | 1 | 0.0070 | 0.0090 |
| | 3 | 1 | 0.0080 | 0.0110 |
| | 4 | 2 | 0.0100 | 0.0130 |
| | 5 | 2 | 0.0120 | 0.0145 |
| | 6 | 2 | 0.0130 | 0.0160 |
| | 7 | 3 | 0.0160 | 0.0200 |
| | 8 | 3 | 0.0190 | 0.0220 |
| | 9 | 3 | 0.0200 | 0.0260 |
| | | | | |
| Correlation Equation: | | | | y = .8248x - 0.0004 |
| Highest PM CEMS Reading: | | | | 0.0260 |
| Limit 1 (Highest PM CEMS X 1.25): | | | | 0.0325 |
| Limit 2 (0.9 X Emissions Limit): | | | | Calculated |

**Figure 1. Calibration Graph Example**



# Compliance Assurance Monitoring
# Test Plan for Determining Particulate Matter

**Aquila–Sibley Generating Station**
**33200 E. Johnson Road**
**Sibley, MO 64088**

August 16, 2006

Prepared by

Aquila, Inc.
and
Burns & McDonnell Engineering Company

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Note: This figure is not on page 5 as was indicated above. It is irrelevant at this point, since the test plan is already complete.

## 1.0 INTRODUCTION

The Aquila-Sibley Generating Station located in Sibley, MO has an approved Compliance Assurance Monitoring (CAM) plan for particulate emissions. The scope of work set forth in this CAM Test Plan is designed to gain acceptance of Teledyne's continuous particulate monitor (Laserhawk 360) for Aquila's CAM obligations to Missouri Department of Natural Resources and Region VII EPA. The CAM performance indicator is a continuous Particulate Monitor, (Laserhawk 360) ("PM CEMS"), manufactured by Teledyne Analytical Instruments. The CEMS output will be used to provide a reasonable level of compliance assurance by indicating ESP performance. The PM CEMS readings shall not be used to directly demonstrate compliance with 10 CSR 10-2.040 limits.

## 2.0 BACKGROUND

The pollutant-specific emission units (PSEU) are three cyclone-fired boilers that route exhaust to a common stack and have a combined heat input rating above 5,000 MMBtu/hr. Each boiler has a dedicated ESP, which controls particulate emissions. All three boilers were constructed before February 15, 1979, and are therefore considered "Existing" per 10 CSR 10-2.040.

1. Emissions Unit:

| | |
|---|---|
| Description: | Boiler #1 – B&W Cyclone, 609.6 MMBtu/hr<br>Boiler #2 – B&W Cyclone, 627.3 MMBtu/hr<br>Boiler #3 – B&W Cyclone, 4094.1 MMBtu/hr<br>(All 3 Units exhaust through Common Stack) |
| Facility: | Aquila-Sibley Generating Station<br>33200 E. Johnson Road<br>Sibley, MO 64088 |

2. Applicable Requirement:

| | |
|---|---|
| Regulation: | 10 CSR 10-2.040, *Maximum Allowable Emission of Particulate Matter From Fuel Burning Equipment Used For Indirect Heating* |
| Pollutants: | Particulate Matter ("PM") |
| Emission Limits: | 0.12 lb PM per MMBtu for each Boiler |

Monitoring Requirements: Per 10 CSR 10-2.040: None.

Per Operating Permit: Current gap-filling compliance demonstration method is a calculation based on coal throughput and emission factor.

Per Proposed CAM: A Teledyne Analytical Instruments Laserhawk 360 particulate monitor installed in the common stack to serve as an indicator of precipitator performance.

3. Control Technology: Electrostatic precipitator (ESP)

## 3.0 TEST PLAN METHODOLOGY AND IMPLEMENTATION SCHEDULE

The CAM Test Plan is comprised of the following five components:

3.1 Monitor Siting and Preliminary Stratification Testing (already performed by TEOM)
3.2 30-Day Pre-Test Monitoring Period, Monitor Range Determination
3.3 7-Day Drift Test
3.4 Correlation Testing

The overall CAM Test Plan implementation schedule is depicted in Figure 3-1. The schedule for tasks and subtasks are detailed for each of the five major components. The specific test methods and procedures that will be employed to successfully execute each component of the CAM Test Plan are described in detail in the following sections.

## 3.1 MONITOR SITING AND PRELIMINARY STRATIFICATION TESTING

*This portion of the CAM Test Plan was completed July 20, 2005, by Thermo using two TEOM sampling units simultaneously as described in this section. Acceptable stratification test results were submitted to MDNR with subsequent installation of an ESC P-5B particulate monitor at the sampling platform. After a few months of operation the P-5B was determined to be inadequate for Sibley operational conditions. Teledyne's Laserhawk 360 was then purchased to replace the ESC P5b as a CAM indicator.*

The PM CEMS (P-5B) was installed at an accessible location downstream of all pollution control equipment. The PM CEMS concentration measurements were conducted from a location considered representative or be able to provide data that can be corrected to be representative of the total PM emissions as determined by the TEOM reference method. A measurement location was selected that minimized problems due to flow disturbances, cyclonic flow, and varying PM stratification (refer to EPA Reference Method 1 for guidance). The PM CEMS was installed at a vertical stack location recommended by

Aquila. From a practical perspective, this was a location with existing platforms, access and power.

Since higher emissions will be created for correlation test purposes by adjusting the performance of the air pollution control device, the PM CEMS measurement location was located as far downstream from the control device as possible in accordance with EPA Reference Method 1 in order to minimize PM stratification that may be created in these cases.

For the selection of an installation location, flow disturbances were minimized and if possible avoided in accordance with the upstream/downstream minimum distances set forth in EPA Reference Method 1. The TEOM reference method measurements were conducted at locations that satisfy the measurement site selection criteria specified in EPA Method 1 of at least eight duct diameters downstream and at least two duct diameters upstream of any flow disturbance. If necessary, testing may be conducted at a location that is two diameters downstream and 0.5 diameters upstream of any flow disturbances. Cyclonic flow will also be minimized and if possible avoided in accordance with the test procedures set forth in EPA Reference Method 2.

A potential installation location was identified utilizing EPA Reference Methods 1 and 2. This potential installation location was then checked for cyclonic flow and for varying PM stratification in accordance with the test procedures set forth in ASTM Method D6831, Determination of Particulate Mass Concentration Using an Automated In-stack Test Method. In accordance with ASTM Method D6381, a TEOM Series 7000 Source Particulate Monitor was used to provide gravimetric particulate measurements in near "real-time". Three, 1-hour ASTM Method D6381 test runs were conducted at the potential installation location for each of 2 different conditions. A total of six (6) test runs were conducted for the 2 different conditions. A traverse of the stack at the installation location was conducted using the TEOM Series 7000 in accordance with EPA Reference Methods 1 & 2. During the traverse real-time particulate matter stratification data was collected at each of the traverse points. After the TEOM testing was completed, the particulate matter stratification data was evaluated for each of the 2 different conditions in order to choose an acceptable measurement point location. Real time particulate data is subject to short-term variability due primarily to ESP rapping. Such temporal variations may be incorrectly identified as evidence of stratification. During evaluation of the TEOM stratification data, an effort was made to account for rapping spikes by, for example, averaging traverse point data over multiple rapping sequences, or by deleting obvious rapping spikes.

## 3.2 30-DAY PRE-TEST MONITORING PERIOD

After completing the initial field installation of the Teledyne Laserhawk 360, the PM CEMS will be operated in accordance with manufacturer's instructions. In this way, Aquila personnel will be able to familiarize themselves with its operation prior to beginning correlation testing. During this initial 30-Day Pre-test Monitoring Period, daily checks (zero and upscale drift, as appropriate) will be performed, and, when any

check exceeds the daily specification (per QA/QC plan), adjustments will be made and any necessary maintenance performed to ensure reliable operation.

The PM CEMS will be adjusted to respond consistently to PM present in the stack under different conditions of boiler load, coal, ESP characteristics and any other performance or test data deemed applicable. The purpose of the 30-Day Pre-test Monitoring Period is to identify the full range of operating conditions and PM emissions to be used in the PM CEMS correlation test.

The relationships between operating conditions and PM CEMS response will be identified, especially those conditions that produce the highest PM CEMS response over 15-minute averaging periods, and the lowest PM CEMS response as well. The objective will be to be able to reproduce these conditions for purposes of the actual correlation testing. The response range of the PM CEMS will be set such that the instrument measures the full range of responses that correspond to the range of source operating conditions that will be implemented during correlation testing. The preliminary reference method testing will be conducted after the 30-day pre-test monitoring period. During this preliminary testing, the PM emission concentration will be measured corresponding to the highest PM CEMS response observed during the full range of normal operation and when perturbing the control equipment. During ESP perturbation, select ESP fields will be turned off for approximate 15-minute periods to observe PM response. MDNR Air Pollution Control Program Enforcement Section will be notified at least 24 hours in advance of any ESP perturbation.

The PM CEMS will be initially operated for a period of approximately 30 days under various operating conditions to identify conditions necessary to produce the two target concentration levels for the correlation testing (see below). During the 30-day pre-test monitoring period, the following key operating parameters will be recorded:

A. Monitor Output
B. Plant Load
C. Fuel Type
D. ESP Secondary Voltage, Current, and Spark Rate for each field

## 3.3 SEVEN (7)-DAY DRIFT TEST

After (or during, if allowed by MDNR) the 30-Day Pre-test Monitoring Period and before performing correlation testing, a 7-day zero and upscale drift test will be performed. The purpose of the 7-day drift test is to demonstrate that the system is capable of operating in a stable manner and maintaining its calibration for at least a 7-day period. The magnitude of the drift will be determined once each day, at 24-hour intervals, for 7 consecutive days while the plant is operating normally. Once the response range has been set and the drift test successfully completed, the response range of the monitor cannot be changed.

The zero (or low-level value between 0 and 20 percent of the response range of the instrument) and upscale (between 50 and 100 percent of the instrument's response range) drift will be checked daily over 7 consecutive days. The PM CEMS will quantify and record the zero and upscale measurements and the time of the measurements. The drift test will be conducted immediately before any automatic or manual adjustments to the PM CEMS zero and upscale settings. Drift will be calculated in accordance with the calculation procedures in section 12.1 of PS 11 and the acceptance criteria for allowable drift will be 4% of the upscale span check value for both zero and span.

## 3.4 CORRELATION TESTING

The standard APCP Proposed Test Plan will be prepared and submitted a minimum of thirty days prior to the test date. This test date will be mutually agreed to by all parties involved.

A minimum of twelve (12) valid runs (e.g. 2 loads, 2 fuel blends and 3 tests per condition) will be required to obtain the correlation equation and correlation coefficient. A run will be declared "not valid" only when performed during a time when conditions are clearly not representative of normal operations. The correlation will be determined according to equation 11-3 of PS 11, and the correlation coefficient will be calculated according to equation 11-14 of PS 11.

Tests will be performed at two (2) or more different PM concentration levels, with a minimum of three (3) tests at each level, if possible. Level 1 encompasses the range from 0 to 50% of the maximum PM concentration available. Level 2 should range from 75% to 100% of the maximum concentration. The source will be operated over the complete range of expected conditions, so as to assure that the data produced is representative. The data gathered during the 30-day pre-test monitoring period will be used to produce the desired concentrations for the test runs. The Aquila-Sibley Generating Station anticipates operating with a fuel mix of 70% - 100% sub-bituminous coal (such as PRB), 0-30% bituminous, and approximately 1% tire-derived fuel (TDF). Heating values range from 8,350 to 12,500 Btu/lb. Actual fuel blend information will be included in the Correlation Test Report.

During correlation testing, the reference method data measurements will be converted into units of pounds PM per MMBtu to establish limits comparable to the regulatory standard (0.12 lbs/MMBtu). The reference method data will be correlated the PM CEMS output using the PS-11 Spreadsheet. The reference method data will be correlated to the mg per actual cubic meter output from the PM CEMS. During operation after testing, the CEMS output, and determination of PM levels with respect to limits, will be conducted only in units of milligrams per actual cubic meter.

The correlation coefficient (r) resulting from the calibration testing must be $\geq .75$. Once the correlation equation has been determined, it will be applied to PM CEMS data collected by the Data Recorder. The point at which an alarm occurs, as well as a reporting requirement and corrective action, will be determined when the hourly average of the PM CEMS output reaches the lower of the following limits:

i. A value equivalent to 1.25 times the highest PM CEMS response value reached during the correlation tests.

ii. A value correlated to 0.9 times the source emissions limit in lb/MMBTU.

The specific stack gas constituents that will be determined as part of the correlation testing include the following:

A. Total suspended particulate (TSP)
B. Flue gas composition ($O_2$, $CO_2$, $H_2O$)
C. Flue gas temperature
D. Flue gas flow rate

The testing methodology to be used for TSP emissions determination is EPA Reference Method 1-4 and 17 for coal-fired boilers.

Each run will include the following measurements:

- average particulate concentration and mass emission rates as measured by USEPA Reference Method 17
- oxygen and carbon dioxide concentrations measured by USEPA Method 3A procedures;
- flue gas moisture measured by USEPA Method 4 procedures;
- flue gas temperature, velocity and volumetric flow rate using USEPA Method 2 procedures.

For each test run coordination will be done for process operations, reference method sampling, and PM CEMS operations. For example, a check will be made to make sure the process is operating at the targeted conditions, reference method sampling is being performed, and the PM CEMS and data logger are operating properly.

The start and stop times of each run will be coordinated between the reference method sampling and the PM CEMS operation. The times for port changes (and other periods when the reference method sampling may be suspended) will be noted on the data sheets so that the PM CEMS data can be adjusted accordingly, if necessary. The time periods for the PM CEMS will be aligned with the reference method measurements to account for the PM CEMS response time.

A minimum of 12 valid runs must be conducted each consisting of simultaneous PM CEMS and reference method measurement sets.

(i) More than 12 sets of CEMS and reference method measurements may be conducted. In this case, certain test results may be rejected so long as the total number of valid test results used to determine the correlation is greater than or equal to 12.

(ii) All data must be reported, including the rejected data.

(iii) The results of up to five test runs may be rejected if shown to be non-representative data ("not valid").

(iv) The basis for rejecting the results of the additional test runs must be explicitly stated in the reference method, PS 11, Procedure 2 of appendix F, or the quality assurance plan.

Simultaneous PM CEMS and reference method measurements will be performed in a manner to ensure that the range of data that will be used to establish the correlation for the PM CEMS is maximized.

An attempt to maximize the correlation range will be performed by following the procedures described in paragraphs (4)(i) through (iv) of PS 11. If the two levels of PM mass concentration can not be obtained as described in paragraphs (i) through (iv), then the procedure described in section 8.6(5) of PS 11 will be used.

(i) Two different levels of PM mass concentration will be obtained by varying process operating conditions, varying PM control device conditions, or by means of PM spiking.

(ii) The two PM concentration levels used in the correlation tests must be distributed over the complete operating range experienced by your source.

(iii) At least 20 percent of the minimum 12 measured data points used should be contained in each of the following levels:
-Level 1: From no PM (zero concentration) emissions to 50 percent of the maximum PM concentration;
-Level 2: 75 to 100 percent of the maximum PM concentration.

If two distinct levels of PM concentration as described can not be obtained, correlation testing must be performed over the maximum range of PM concentrations that is practical for the PM CEMS. To ensure that the range of data used to establish the correlation for the PM CEMS is maximized, one or more of the steps in paragraphs (5)(i) through (iv) of PS 11 must be followed.

(i) Zero point data for in-situ instruments should be obtained, to the extent possible, by removing the instrument from the stack and monitoring ambient air on a test bench.

(ii) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(iii) Zero point data also can be obtained by performing TEOM reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas).

(iv) If none of the steps in paragraphs (5)(i) through (iii) of this section are possible, you must estimate the monitor response when no PM is in the flue gas (e.g., 4 mA = 0 mg/acm).

## Appendix A

## USEPA REFERENCE METHOD 17 - PARTICULATE

**Testing Equipment High-Volume Source Sampling Train.** An Acurex Corp., aerotherm high-volume stack sampler (Model HVSS-045) will be used at the sampling location(s). The HVSS particulate sampling train consisted basically of an appropriate length aluminum probe with a calibrated Type K (chromel/alumel) thermocouple; a stainless steel, in-stack filter holder; a standard lexan/stainless steel impinger assembly with a calibrated Type K (chromel/alumel) thermocouple located at the impinger outlet; a 3/4-hp, shaft-sealed, carbon vane vacuum pump assembly with a vacuum gauge; a control unit with an elapsed time indicator, a temperature selector switch, a temperature indicator (potentiometer), temperature controllers, calibrated magnehelic gauges, a calibrated dry gas meter, and a calibrated variable-diameter orifice; and umbilical and various interconnecting hoses, fittings, and valves. An appropriately sized stainless steel nozzle, a calibrated Type K (chromel/alumel) temperature sensor, a static pressure tube, and a calibrated S-type pitot tube are integral parts of the probe assembly.

The vacuum pump unit will be used to control gas sampling rates. The control unit will be also used to monitor elapsed sampling times, temperatures, velocities, static pressure, gas sampling rates, and sampled gas volumes.

**Integrated Gas Sampling Train.** Flue gas will be collected at the sampling location(s) for analysis with an integrated gas sampling train. The sample will be collected at the outlet of the particulate control meter.

### Sampling Procedures

Prior to field testing, the following procedures will be performed:

*Compliance Assurance Monitoring Test Plan – August 2006*

All instruments will be checked and calibrated. Teyo-Roshi filters No. 86R 30 x 100 millimeter, glass-fiber thimble filters with a 99.9 percent retention of 0.25 micron particles will be individually numbered, placed separately in similarly numbered aluminum mailing cartons, oven-dried at 220°F for two to three hours, cooled in a desiccator for two hours, and individually weighed on a Sartorious analytical balance to the nearest 0.1 milligram, then weighed every six hours, minimum, until two consecutive weights within ±0.5 milligram will be obtained. Several 250 milliliter crucibles will be dessicated for a minimum of 24 hours and weighed in the same manner as the filters and mailing cartons. Also, several 350-gram quantities of Type 6-16 mesh indicating silica gel will be weighed out on a Mettler top-loader electric balance and individually placed into separate airtight polypropylene storage bottles.

The number of sampling points and positions of the points in the flue at the sampling locations(s), and the sampling time at each point will be determined prior to the particulate testing. The sampling procedures will be performed in accordance with the Environmental Protection Agency's Reference Method 17, "Determination of Particulate Emissions from Stationary Sources," in the Title 40, *Code of Federal Regulations,* Part 60, Appendix A.

An HVSS sampling train will be prepared in part at the sampling location(s), before each test run, in the following manner:

An appropriately sized sampling nozzle will be installed onto the inlet of a filter holder and capped. The probe will be then dimensioned and marked with glass-cloth tape at increments that corresponded with the predetermined sampling point positions in the flue. A standard impinger assembly will be prepared by adding 250 milliliters of three percent concentration hydrogen peroxide, in lieu of distilled water, to each of the first two lexan impingers. This will be done to partially trap sulfur dioxide and sulfuric acid mist carryover, and to prevent a strong concentration of these contaminants from contacting and possibly damaging the vacuum pump or dry gas meter. The third lexan impinger will be left dry and the fourth will be filled with 350 grams of Type 6-16 mesh indicating silica gel. This entire impinger assembly will be then placed into an ice bath. A glass-fiber thimble will be removed from its carton and placed inside a filter holder. The filter holder will be then attached to the sampling probe inlet. Next, umbilical and sampling hoses will be connected to the sampling probe, impinger unit, vacuum pump, and control unit, accordingly. All magnehelic gauges will be checked and zeroed. The entire sampling train assembly will be leak-checked at 15 inches of mercury vacuum, minimum, for one minute and the leakage rate recorded. A leakage rate less than 0.02 cfm and no vacuum loss will be considered acceptable. After the HVSS particulate sampling train had been assembled, and the entire system leak-checked, as previously described, the particulate sampling will be performed. Prior to the particulate sampling, a preliminary temperature and velocity traverse, orsat analysis, and calculations will be performed to determine a correct nozzle and orifice size, and these factors will be used in calculating the isokinetic sampling rate for each sampling point. Knowing the actual pressure differential across the pitot tube used, the isokinetic sampling rate will be calculated at each sampling point using a Texas Instrument Model 74 pocket computer.

Three test runs will be performed at the sampling location(s). A total of 16 points (four points from each of the four sampling ports) will be sampled. Each point will be sampled for a period of three minutes at a

calculated isokinetic sampling rate. The sampling data for each test run will be recorded on a field test form during each of the sampling period.

After the completion of a test run, the following procedures will be performed:

A final leak-check will be performed at 15 inches of mercury vacuum, minimum, for one minute and the leakage rate recorded. The flue gas moisture collected in the first three impingers will be measured and recorded. The moisture laden silica gel in the fourth impinger will be transferred to an appropriately marked, airtight polypropylene storage bottle and retained for later weighing. The weight gain of the silica gel moisture collection will be added to the measured moisture condensed during the test run to determine the total moisture collected for that run. The sampling nozzle and filter holder will be capped and taken to a clean area for sample recovery. At the recovery area, the filter will be carefully removed from the filter holder and transferred to its carton for later desiccation and weighing. The sampling nozzle and filter holder inlet will be washed with nanograde acetone. The acetone washing and an acetone blank will be collected in appropriately labeled polypropylene sample bottles and retained for later evaporation, desiccation, and weighing. Flue gas composition (percent $CO_2$, and percent $O_2$) will be determined by taking, throughout each test run, by an integrated gas sampling train several samples of the gas collected, simultaneously, with the particulate sampling. The integrated gas sample will be collected from the discharge of the particulate control unit. The sampling train will be set at a predetermined constant flow rate to obtain an adequate sample. The integrated bags will then be analyzed by the O2 and CO2 monitors in the Burns & McDonnell testing trailer. The required quality assurance checks and calibration of the monitors will be recorded as required by Method 3A.

## Analytical Procedures

After the field testing will be completed, the following procedures will be performed:

> The silica gel, filters, carton, acetone washings, and acetone blank(s) from the test runs will be analyzed by Burns & McDonnell Engineering Company, Inc., Kansas City, Missouri. The analytical procedures will be performed in accordance with the Environmental Protection Agency's Reference Method 17, "Determination of Particulate Emissions from Stationary Sources," in the Thursday, August 18, 1977, *Federal Register*, "Standards of Performance for New Stationary Sources."

Each silica gel moisture collection will be weighed directly out of its polypropylene storage bottle on a Mettler electronic balance with a sensitivity of 0.1 gram. Each filter and carton will be oven dried at 220°F for two to three hours, cooled in a desiccator for two hours before weighing, and weighed every six hours, minimum, until two consecutive weights within ±0.5 milligram are obtained. Each acetone washing and acetone blank will be transferred from its sample bottle to a preweighed aluminum tin for evaporation on a low-temperature hot plate at 130°F. When the acetone in a crucible has completely evaporated, the crucible will be transferred to a desiccator for further drying at room temperature for a minimum of 24 hours before weighing, and weighed every six hours, minimum, until two consecutive weights within ±0.5 milligram are obtained. Each acetone blank collected will be used to determine the amount of residual weight each aluminum tin retained due to acetone impurities. Each filter and carton, acetone washing and acetone blank will be individually weighed on a Sartorious analytical balance with a sensitivity of 0.1 milligram.

All test instruments will be recalibrated to determine the deviation percentage.

# QUALITY ASSURANCE & QUALITY CONTROL PLAN

# PARTICULATE MATTER CONTINUOUS EMISSIONS MONITORING SYSTEMS

Aquila
Sibley Generating Station

Prepared by:

Aquila Environmental Services

Revision Number:_____
Date of Revision:_____

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# SECTION 1 – THE QUALITY ASSURANCE PLAN

This Quality Assurance (QA) Plan is the basis for assessing and maintaining the quality of particulate matter continous emission monitoring system ("PM-CEMS") data. The QA Plan has been prepared for Aquila, operators of one (1) PM-CEMS at the Sibley Generating Station. The PM-CEMS are installed pursuant to 40 CFR Part 64, Compliance Assurance Monitoring ("CAM"). As such, the PM-CEMS is not to be used for direct compliance demonstration for any applicable regulation. Per Part 64.3(a), the purpose of the PM-CEMS is to "provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit." Specifically, the PM-CEMS will provide data to help in the operation and maintenance of the electrostatic precipitators ("ESP") installed at this facility. Similarly, 40 CFR Part 60, Appendix F, Procedure 2 has been partly utilized to develop this QA Plan, but is not directly applicable to Sibley's PM-CEMS per Appendix F, Procedure 2, Section 1.0. Also, Two documents related to Sibley's CAM have been developed and approved by the Missouri Department of Natural Resources ("MDNR"). The two documents are Sibley's CAM Plan and CAM Test Plan. Where conflicts arise between the Sibley CAM Plan/Test Plan and 40 CFR Part 60 regulations, the MDNR-approved Plans will be followed.

Table I below illustrates the PM-CEMS that have been installed at the facility.

**Table I. PM-CEMS installed and certified at Aquila's Sibley Generating Station**

| Mfr/Model | Serial Number | Measurement Range | Location | Correlation Test Date |
|---|---|---|---|---|
| Teledyne Monitor Labs / LaserHawk 360 | TBD | TBD | Common Stack | TBD |

## 1.1 QUALITY ASSURANCE POLICY, GOAL, AND OBJECTIVES

Quality Assurance (QA) and Quality Control (QC) are two independent and interrelated functions. Quality Assurance can be defined as the system of activities to provide assurance that the QC is performing adequately.

A QA Plan has two functions:

(1) QA – the assessment of the quality of the data (accuracy and precision) and, (2) QC – activities that maintain or improve data quality. Both functions form a control loop. When accuracy or precision is unacceptable, QC must increase until the quality of data is acceptable.

Quality control functions are usually a series of frequent internal checks, such as system inspections, periodic calibrations, and routine maintenance. Quality assurance, on the other hand, involves less frequent external checks on data quality. These external checks may include independent system audits, third party sampling and analysis for accuracy and precision, comparison to known calibration standards or inter-laboratory audits. This Quality Assurance Plan encompasses both QA and QC functions, and whenever possible, specific activities are identified by the function that is fulfilled by the activity.

## 1.2 DISTRIBUTION AND DOCUMENT CONTROL

This QA Plan will be reviewed on an annual basis. Revision tracking system will be provided on the front page of this document and includes revision number and date of revision.

### 1.2.1 MAINTENANCE OF THE QA/QC PLAN

To properly maintain the QA Plan, the following activities are monitored:

(1) Maintain a current list of QA/QC plan holders.

(2) Prepare revisions and updates of the QA/QC Plan as a result of the following:

- Changes in regulations.
- Modifications or improvements of QA/QC procedures.
- Changes in personnel or organization.
- Replacement of PM-CEMS components.
- Modifications to operating permit.

## 1.3 ORGANIZATION AND RESPONSIBILITY

Specific facility personnel are assigned responsibility for the PM-CEMS operational status instrument maintenance and system control. The following are provided as a guideline, which organize responsibilities for the operation and maintenance of a PM-CEMS.

### 1.3.1 RESPONSIBLE OFFICIAL AND DESIGNEE

The Title V Permit Responsible Official or designee is responsible for reviewing and signing all quarterly reports.

### 1.3.2 SIBLEY INSTRUMENTS AND CONTROLS DEPARTMENT

Has overall responsibility for the operation and maintenance of the PM-CEMS, and generation of appropriate reports. The department reports all major problem associated with the PM-CEMS to the Plant Manager and Environmental Services.

### 1.3.3 ENVIRONMENTAL SERVICES DEPARTMENT

Environmental Services is responsible for corresponding with regulatory agencies, including reviewing/submitting all required reports, and maintaining compliance with Sibley's Title V Permit.

## 1.4 FACILITIES, EQUIPMENT, AND SPARE PARTS INVENTORY

The Sibley Generating Station consists of three (3) steam generating units, with each unit equipped with a dedicated ESP to control particulate emissions. All three units exhaust through a common stack, where the PM-CEMS is located.

The PM-CEMS is wired to a programmable logic controller located in the CEM shelter and will record data in the Continuous Emission Monitoring System DAHS.

### 1.4.1 PARTICULATE MATTER CONTINOUS EMISSION MONITORING SYSTEM

The particulate monitoring system utilized is a Teledyne Monitor Labs 360 particulate monitor, located on the Sibley common stack. Measurement of particulate concentration is accomplished by passing a beam of laser light into the duct and measuring the intensity of the backscattered light.

### 1.4.2 RECOMMENDED SPARE PARTS AND STACK DRAWINGS

A list of spare parts is included in the instrument operations manual. Stack drawings and process diagrams are also kept on site and available for review.

## 1.5 METHODS AND PROCEDURES – ANALYSIS AND DATA ACQUISITION

The PM-CEMS data acquisition system (DAS) is an automated system that records PM-CEMS data and provides readouts as one-minute averages, which are used in subsequent calculations and report preparation. Reports prepared by the system include alarm, calibration, and emission reports.

The DAS is capable of reading all values over the full range of each measurement device and creates a permanent record of all required measured and calculated data for storage, review, and reporting. A continuous readout in units allowed by the Sibley CAM Plan is recorded.

## 1.6 CALIBRATION AND QUALITY CONTROL CHECKS

A set of operation and maintenance manuals for all systems components is maintained in the CEMS shelter. These manuals provide complete descriptions of the PM-CEMS including theory, installation, operation, and maintenance.

Factory supplied filter standards are used to calibrate the instrument at a reference zero and upscale span value. These calibration standards will be maintained in accordance with the manufacturer's recommendations. Following this calibration an internal "zero-span" cycle will be initiated, thus establishing initial values for future reference. Daily "zero-span" cycles will follow with the results stored in the data system and compared with the initial values. Should either of the "zero or span" value error exceed plus or minus 4% of the starting value, an alarm will be initiated to signal the need for recalibration of the instrument to the factory standards.

In addition a quarterly reference calibration will be performed as described in the instrument operations manual. The factory standards will be used to measure instrument response at a zero and upscale value. Should either of these readings exceed the factory standard by more than plus or minus 4% of the full-scale measurement range, the instrument will be reset to the factory standard values. Finally, routine scheduled maintenance procedures will be established in accordance with the manufacturer's recommendations.

## 1.7 MAINTENANCE - PREVENTIVE

The preventive maintenance program for the PM-CEMS is based on the equipment manufacturers recommended procedures.

## 1.8 SYSTEMS AUDITS

A systems audit involves a general inspection of the monitoring system. It is intended as a walk through audit and used to provide a quick assessment of the availability of data, general effectiveness of operation and maintenance, and the completeness of recordkeeping procedures. Systems audit involves the following areas:

- Administrative
  - Maintenance logs – timely, complete
  - Recordkeeping – completeness, available
  - Verify correct range values entered into the data acquisition system
- Technical
  - Printer – operational, legible printouts consistent with process conditions
  - Data system – cabinets clean, areas maintained

- Monitor enclosure – clean, all systems operational
- Purge air blowers – operational

## 1.9 PERFORMANCE AUDITS

The following performance audits are required to quality assure PM-CEMS data. These audits are based upon 40 CFR 60, Appendix F, Procedure 2, however Appendix F is not directly applicable to the PM-CEMS.

### 1.9.1 ABSOLUTE CORRELATION AUDIT (ACA)

An Absolue Correlation Audit is required once each calendar quarter but no sooner than 2 months after the previous ACA. ACAs are not required in quarters in which a Response Correlation Audit (RCA) is performed.

- Challenge the PM-CEMS three times at each audit point and use the average of the three responses in determining accuracy at each audit point. Audit points are audit filters that produce particulate levels of known values.

| Audit Point | Audit Range |
|---|---|
| 1 | 0 - 20 percent of measurement range |
| 2 | 40 -60 percent of measurement range |
| 3 | 70 -100 percent of measurement range |

- Challenge the PM-CEMS at each audit point for a sufficient period of time to ensure that the PM-CEMS response has stabilized.
- Alternate filter insertions so that no filter is measured twice in succession during the audit.
- The difference between the actual known value of the audit standard and the response of the monitor is used to assess the accuracy of the PM-CEMS.
- The beginning of the out of control period is the time corresponding to the completion of an unsuccessful ACA. The end of the out of control period is the time corresponding to the completion of the subsequent successful calibration test.
- During an out of control period the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.
- The PM-CEMS is considered out of control if the required quarterly absolute correlation audit is not conducted during a calendar quarter.

The criteria for excessive inaccuracy are:

- ± 10% of the average audit value or 7.5% of the applicable standard, whichever is greater.

- Repeated excessive inaccuracies (i.e., out of control) conditions resulting from the quarterly audits, indicates the QC procedures are inadequate or that the CEMS is incapable of providing quality data.

**NOTE: The ACA must be conducted using the calibration kit with the same serial number as the particulate monitor.**

### 1.9.2 RELATIVE RESPONSE AUDIT (RRA)

Perform a Relative Response Audit (RRA) annually. Perform a RRA by collecting three (3) sets of simultaneous Reference Method data and Particulate Monitor data. Determine compliance with the RRA using the criteria specified in 40CFR60, Appendix F. If failed RRA tests trigger the need to conduct an RCA and/or new correlation test, performance and acceptance criteria will be based on the MDNR-approved Sibley CAM Plan and CAM Test Plan.

The RRA will be performed annually and will replace the Absolute Correlation Audit in the quarter when both audits are due.

### 1.9.3 RESPONSE CORRELATION AUDIT (RCA)

An RCA is required to be performed at least once during each Title V Operating Permit renewal cycle (i.e. once per 5-year period). The RCA is conducted by collecting a minimum of twelve (12) sets of simultaneous Reference Method data and Particulate Monitor data. To pass an RCA the following criteria must be met

- For all 12 data points, the PM-CEMS response value can be no greater than the greatest PM-CEMS response value used to develop the correlation curve;
- For 9 of the 12 data points, the PM-CEMS response value must lie within the PM-CEMS output range used to develop the correlation curve.

The criteria for excessive inaccuracy are:

- At least 75% of a minimum number of 12 sets of PM-CEMS/reference method measurements from the test must fall within a specified area on a graph developed by the calibration relation regression line over the calibration range and the tolerance interval set at ± 25% of the emission limit.
- The specified area on a graph is (a) bounded by two lines parallel with the calibration regression line, and offset at a distance ±25% of the numerical emission limit from the calibration regression line on the y-axis and (b) traversing across the calibration range bounded by the lowest and the highest CEMS reading of the calibration test on the x-axis.

The PM-CEMS is considered out of control if the required RCA is not performed during the permit renewal interval (once every 5 years). See 2.6.2 Relative Correlation Audit for details on failure of an RCA. The RCA will replace the Absolute Correlation Audit and Relative Response Audit when done in the same quarter. In the event that a new correlation test is required, the performance and acceptance criteria will be based on the MDNR-approved Sibley CAM Plan and CAM Test Plan.

## 1.10 CORRECTIVE ACTION PROGRAM

Whenever the PM-CEMS is found to be "out of control" the data generated from the system will not be used to demonstrate a reasonable level of compliance assurance with permit limits or data capture requirements. Corrective action is performed "as soon as possible" after determining the PM-CEMS is not operating according to manufacturer's specifications or is "out of control."

Corrective action is defined as the resolution of problems that occur on a non-routine basis.

### 1.10.1 SUGGESTED CORRECTIVE ACTION

References to specific PM-CEMS troubleshooting procedures are listed in the Instrument's Operation Manual.

## 1.11 REPORTS

Documentation of QA/QC data and information is an integral part of any QA Plan. This section describes reports and other records that provide adequate documentation of QA/QC activities. The two primary means of documentation used are:

- Data Acquisition System (DAS).
- Manually prepared QA/QC forms, logs and reports.

During QA audits, the DAS will be operated to collect data in a normal fashion, and will print all instantaneous emissions values for real time comparison with audit standards. The DAS is used not only to document QA/QC data and information, but it also serves as the PM-CEMS data acquisition and processing system.

A number of written QA/QC reports are needed to provide supporting documentation of the continued operation of the PM-CEMS in an acceptable manner. All reports are used to notify individuals of problems related to operation of the PM-CEMS. Completion of these reports is intended to assist in identifying the need for remedial maintenance, training, or supply action, as well as the need to revise operating procedures for this QA Plan.

# SECTION 2 – STANDARD OPERATING PROCEDURES

Quality control checks may be defined as those checks performed on a routine basis such as system inspections, periodic calibrations and routine maintenance.

**LASER SAFETY WARNING: Any person working on or auditing the particulate monitoring equipment must be adequately trained in Laser Safety and have thoroughly reviewed the operations manual due to the inherent dangers in working with Laser equipment.**

## 2.1 START-UP AND OPERATION

The Instrument and Controls Department maintains a detailed written procedure for start-up of the equipment at the facility. The document contains the step-by-step procedures for starting up and shutting down all equipment at the facility.

## 2.2 PM-CEMS INSPECTION AND PREVENTIVE MAINTENANCE

A CEMS maintenance log is maintained in the Unit 3 computer room to document system operational status and record any maintenance performed. An electronic file contains a record of the PM-CEMS calibration activities.

The routine inspection begins with a visual inspection of the electrical systems and components. This procedure allows early detection of accidental damage to the PM-CEMS.

The plant technician will examine the data acquisition system's computer screens and files to verify the computer has the correct time, date, and settings as applicable. A calibration history of the calibrations is reviewed for excessive calibration drift on a weekly basis or more often as needed.

Indicator lights and alarms on the system or monitor control panel are examined next. The system indicator lights notify the plant Technician of out-of-range conditions or other potential problems associated with the PM-CEMS. Action is initiated immediately if an indicator light is illuminated; subsequent data acquired may be suspect and will be flagged accordingly.

## 2.3 CALIBRATION PROCEDURES

The 360 calibration cycle automatically checks and corrects zero and span drift. The calibration cycle can be programmed to activate at selectable hourly intervals, manually activated from either the control room or stack, or externally activated from the programmable logic controller or data acquisition system.

### 2.3.1 DAILY CALIBRATION CHECK

A daily calibration is performed for the PM-CEMS that is measuring and reporting particulate concentration. Typically the zero and span calibration are programmed to be performed once every 24-hours. The zero calibration is conducted at a measurement level between zero and twenty (0 – 20) percent of instrument measurement range. The span calibration is conducted at a measurement level between fifty and one hundred (50 – 100) percent of instrument measurement range. A copy of the daily calibration for the PM-CEMS will be filed or electronically archived. Table II below illustrates calibration ranges of the PM-CEMS.

**Table II. Recommended zero and high level calibration levels**

| Emission Point | ZERO VALUE (0 – 20% RANGE) | SPAN VALUE (50 – 100% RANGE) |
|---|---|---|
| Common stack | TBD | TBD |

### 2.3.2 DAILY PM-CEMS DRIFT ASSESSMENT AND CORRECTIVE ACTION

The PM-CEMS typically performs a calibration once every 24 hours. The PM-CEMS shall be adjusted when the drift exceeds twice the performance specificaion. The PM-CEMS are considered out-of-control when:

(1) Either the zero or span calibration drift exceeds 4 percent the applicable performance specification in 40 CFR 60 for five (5) consecutive days, or

(2) Either the zero or span calibration drift exceeds 8 percent the applicable performance specification in 40 CFR 60 for any single calibration.

Table III below illustrates out-of-control calibration drift criteria for the PM-CEMS.

**Table III. Calibration Drift Criteria**

| Monitor | Level at which CEM shall be adjusted | Level at which CEM is Out-of-Control | |
|---|---|---|---|
| | | Any one day | Any five consecutive days |
| Common stack | 4% | 8% | 4% |

If an out-of-control condition exists, corrective action will be initiated immediately. Corrective action steps are identified in the Teledyne Monitor Labs Operation and Maintenance Manual or the Analyzer Operator Manual. Corrective action steps may include: adjustment of the electronics and potentiometers, care of the optics, replacement of the dessicator and/or purge blower air filter. Calibration drift checks will

be repeated following corrective action to verify the PM-CEMS meets calibration requirements and is no longer out-of-control.

During an out-of-control period, the data collected by the PM-CEMS will not be used in determining particulate emissions compliance; nor will it be counted toward meeting the minimum data availability requirements.

## 2.4 PREVENTIVE MAINTENANCE PROCEDURES

The recommended maintenance schedule is used initially as a guideline and then adjusted for the application following actual field experience. Preventive maintenance checks and procedures are identified in the Maintenance and Trouble Shooting Section of the analyzer Operator Manual.

Some items in the recommended periodic maintenance chart, such as filter changes, will not exhibit a failure condition until probable damage to other components has resulted. These items require special attention for determining replacement frequency. Close and continuous observation of the operating characteristics of the system, with particular notation of any shift, either sudden or prolonged, in one direction of any of the many visual indicators in the system, should prompt a maintenance response and prevent loss of data and/or equipment damage.

The system's equipment alarms are indications that maintenance is required. They do not necessarily indicate the data is invalid. However, they do indicate that the system is operating outside of a design tolerance and inaccurate data and equipment damage will occur if the system is allowed to continue operation with the problems. For this reason, the alarms are exercised on a regular basis to assure that they are operational.

One of the best indications of system performance is the validity of the data it is generating. Scrutiny of the daily calibration results will indicate whether or not there is a need for maintenance.

## 2.5 CORRECTIVE MAINTENANCE PROCEDURES

A trouble-shooting section is included in each analyzer Operator Manual.

Zero and calibration drift checks will be conducted immediately prior to any maintenance, if possible. Additionally, zero and calibration drift checks will be conducted immediately following any maintenance. If the post-maintenance zero or calibration drift checks show drift in excess of twice the applicable performance specifications, recalibration is conducted in accordance with the Operator Manual.

## 2.6 PERFORMANCE AUDIT PROCEDURES

### 2.6.1 ABSOLUTE CORRELATION AUDIT (ACA)

ACAs are required on a quarterly basis, unless an RRA or RCA is conducted in that quarter. The audit is completed and the results are determined using the procedures contained in 40 CFR 60, Appendix F. Acceptable ranges for the ACA filters are included in Table IV.

**TABLE IV. ACA Audit Filters**

| Emission Point | LOW (0 – 20% of Range) | MID (40 – 60% of Range) | HIGH (70 – 100% of Range) |
|---|---|---|---|
| Common stack | TBD | TBD | TBD |

For EACH Audit

1. Record the requested data in the appropriate blocks on the data sheet(s) for the analyzer(s) being checked. Each analyzer should have its own data sheet.

2. Open the optical head on the particulate monitor.

3. Install the calibration jig onto the optical head.

4. Alternately insert each of the 3 known particulate standards into the calibration jig. Leave each filter in place for 5 minutes to ensure stable readings. Repeat this process until 3 readings have been made with each filter.

5. Uninstall the calibration jig from the optical head.

6. Close the optical head so that the instrument is reading process conditions again.

7. Calculate and record the average of the monitor's responses (A) for each level of calibration filter (high-, mid- and low-).

8. Using the equations in Appendix D, calculate the mean value and and correlation accuracies for each particulate level.

The monitor passes the ACA if, at all three levels of filters, the percentage difference is less than or equal to 10.0 percent of the average audit value or the percentage difference is less than or equal to 7.5 percent of the applicable particulate standard. If these criteria are not met at any level, the monitor is considered out-of-control. Indication will be made on the data sheet(s) whether the monitor(s) passed or failed the calibration error test.

## 2.6.2 RELATIVE RESPONSE AUDIT (RRA)

The Relative Response Audit requires the support of an independent stack sampling team. Three (3) simultaneous measurements are taken by the contracted test team and the particulate monitor in accordance with 40CFR60, Appendix F, Performance Specification 2. It is recommended that the test team perform duplicate measurements to ensure the maximum accuracy of the sampling.

The RRA will be conducted annually unless an RCA is completed during that same period then an RRA will not be required.

The monitor passes the RRA if all of the following occur:

(1) The response from all three measurements is less than the highest response used to generate the correlation curve,
(2) At least two of the three responses lie within the PM-CEMS output range used to develop the correlation curve, and
(3) At least two of the three responses fall within the area specified in the correlation curve and defined as the regression line ± 25% of the numerical emission limit.

## 2.6.3 RELATIVE CORRELATION AUDIT (RCA)

The Relative Response Audit is conducted in accordance with 40 CFR Part 60, Appendix F, Performance Specification 2, and requires the support of an independent stack sampling team. The MDNR-approved Sibley CAM Plan and CAM Test Plan shall be followed where conflicts arise between 40 CFR Part 60 and the Sibley CAM Plan and CAM Test Plan.

The correlation test includes:

(1) Paired reference method trains are recommended for collecting manual PM data to identify and screen the reference method data for imprecision and bias;
(2) test runs may be shorter than 60 minutes in duration (e.g., 20 to 30 minutes);
(3) convert the reference method results to units consistent with the conditions of the PM CEMS measurements (e.g., mg/acm);
(4) during each test run coordinate process operations, reference method sampling and PM CEMS operations to ensure that the process is operating at the targeted conditions
    a. coordinate the start and stop times of each run between the reference method sampling (if batch sampling start the reference method at the same time as the PM CEMS sampling);
    b. note the times for port changes (and other periods when the reference method sampling may be suspended) on the data sheets (to make any required adjustments);
    c. properly align the time periods for the PM CEMS and the reference method measurements to account for the PM CEMS response time;

i. conduct a minimum of 12 sets of CEMS and reference method measurements – additional measurements may be completed and rejected but a minimum of 12 sets is required;
ii. report all data, including rejected data;
iii. up to five test runs may be rejected without explanation;
iv. explicit explanations are required for greater than five rejected runs;

(5) simultaneous PM CEMS and reference method measuremens must be performed in a manner to ensure that the range of data that will be used to establish the correlation for the PM CEMS is maximized. First attempt to maximize the correlation range by following the procedures described in 5 (i) through (iv) (this section). If the three levels described in (i) through (iv) cannot be achieved, use the procedures in section 8.6(5);

i. attempt to obtain the three different levels of PM mass concentration by varying process operating conditions, varying PM control device conditions, or by means of PM spiking;
ii. the three PM concentration levels used in the correlation tests must be distributed over the complete operating range experienced by the source;
iii. at least 20 percent of the minimum 12 measured data points should be contained in each of the following levels:

| Correlation Test /RCA | |
|---|---|
| Level 1 | from no PM (zero concentration) emissions to 50 percent of the maximum PM concentration |
| Level 2 | 25 yo 75 percent of the maximum PM concentration |
| Level 3 | 50 to 100 percent of the maximum PM concentration |

iv. although the above levels overlap, only apply individual run data to one level;

(6) if three distinct levels of PM concentration cannot be obtained, perform correlation testing over the maximum range of PM concentrations that is practical for the PM CEMS;

(7) ensure that the range of the data used to establish the correlation for the PM CEMS is maximized by the following:
a. zero point data for in-situ instruments is obtained by removing the instrument from the stack and monitoring ambient air on a test bench or
b. perform a manual reference method measurement when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when the process is not operating, but the fans are operating) or
c. if neither of the steps are possible, estimate the monitor response when no PM is in the flue gas (e.g., 4 mA = ) mg/acm).

(8) Failure of an RCA requires the following actions:
a. Combine RCA data with data from the active PM-CEMS correlation and perform the mathematical evaluations defined in PS-11 for development

of a PM-CEMS correlation, including examination of alternate correlation models (i.e., linear, polynomial, logarithmic, exponential, and power). If the expanded data base and revised correlation meet PS-11 statistical criteria or Sibley CAM Plan/Test Plan criteria, whichever is less stringent, then use the revised correlation;

b. If the criteria specified above (in a. above) are not achieved, develop a new PM-CEMS correlation based on revised data. The revised data set must consist of the test results from only the RCA. The new data must meet all requirements of the MDNR-approved Sibley CAM Plan and Test Plan to develop a revised PM-CEMS correlation for 12 sets. The PM-CEMS is considered to be back in controlled status when the revised correlation meets all of the performance criteria specified in the MDNR-approved Sibley CAM Plan and Test Plan;

c. If the actions specified above (in a. and b.) do not result in an acceptable correlation, evaluate the cause(s) and comply with the actions below within 90 days after the completion of the failed RCA:
    i. Completely inspect the PM CEMS for mechanical or operational problems, repair the PM CEMS and repeat the RCA;
    ii. If you must relocate the PM CEMS to a more appropriate measurement location, perform a new correlation test according to the MDNR-approved CAM Plan and Test Plan;
    iii. The characteristics of the PM or gas in the flue gas stream may have changed such that the PM CEMS technology is no longer appropriate. If this is the case, install a PM CEMS with measurement technology that is appropriate for the flue gas characteristics. Perform a new correlation test according to the MDNR-approved Sibley CAM Plan and Test Plan;
    iv. If the corrective actions above (3i through 3iii) were not successful, petition the regulators for approval of alternative criteria or an alternative for continuous PM monitoring.

## 2.7 SYSTEM AUDIT PROCEDURES

System audits will be performed and recorded in the maintenance logbook. The following checks will be recorded during the system audit and may be revised as operating experience dictates.

(1) Multiday calibration reports for the previous seven (7) days for all PM-CEMS. Check for trends in drift.
(2) Verification that correct span values are entered into the computer.
(3) Examination of the PM-CEMS, noting any alarms displayed and/or that the readings are consistent with monitor operation.

Quarterly system audits will be performed to:

(1) Check maintenance logbooks for timely and completed repairs.

(2) Determine the printer is operational and printout is legible, readings are consistent with process conditions.
(3) Acknowledge that the computer and monitor areas are clean and well maintained.
(4) Determination that the purge air blower is operational and alignment of monitor is correct.

## 2.8 DATA BACKUP PROCEDURES

The PM-CEMS data are retained on a data acquisition and handling system (DAS). Particulate Emissions Data is backed up as part of the network or tape backup procedures used for all emissions data collected at the facility.

## 2.9 DATA REPORTING PROCEDURES

The results from each audit or the routinely generated particulate data are reviewed prior to it being included into reports submitted to the regulatory agencies.

As part of the operating permit requirements, all PM-CEMS data are made available for review, in the form of a computerized database or printed opacity logs, for 24 months. Quarterly compliance reports are submitted to the MDNR within 30 days of the ending quarter as defined in the operating permit. All data will be maintained for the life of the current Title V Operating Permit (5 years).

Note that Appendix B of the CAM Test Plan is not included above. Appendices A through D of the CAM QA/QC Plan are not included either.

Prepared by:

Cheryl Steffan

Cheryl Steffan
Environmental Engineer

STATE OF MISSOURI
Matt Blunt, Governor • Doyle Childers, Director
DEPARTMENT OF NATURAL RESOURCES
www.dnr.mo.gov

SEP 2 9 2006

CERTIFIED MAIL, 70012510000573491681
RETURN RECEIPT REQUESTED

Mr. Greg Lee, Plant Manager
Kansas City Power & Light – Montrose Generating Station
400 SW Highway P
Clinton, MO 64735

Re: Kansas City Power & Light – Montrose Generating Station, 083-0001
Permit Number: **OP2006-070**

Dear Mr. Lee:

Enclosed with this letter is your Part 70 operating permit. Please review this document carefully. Operation of your installation, in accordance with the rules and regulations cited in this document, is necessary for continued compliance. It is very important you read and understand the requirements contained in your permit.

If you have any questions or need additional information regarding this permit, please contact the Air Pollution Control Program at (573) 751-4817, or you may write to the Department of Natural Resources' Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102. Thank you for your time and attention.

Sincerely,

AIR POLLUTION CONTROL PROGRAM

Kyra L Moore

for Michael J. Stansfield, P.E.
Operating Permit Unit Chief

MJS: csk

Enclosures

c: Ms. Tamara Freeman, US EPA Region VII
Kansas City Regional Office
PAMS File: 2004-06-071

Recycled Paper

**Missouri Department of Natural Resources**
Air Pollution Control Program

# PART 70
# PERMIT TO OPERATE

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

**Operating Permit Number:** OP2006-070
**Expiration Date:** SEP 2 8 2011
**Installation ID:** 083-0001
**Project Number:** 2004-06-071

**Installation Name and Address**
Kansas City Power & Light – Montrose Generating Station
400 SW Highway P
Clinton, MO 64735
Henry County

**Parent Company's Name and Address**
Kansas City Power & Light Company
PO Box 418679
Kansas City, MO 64141

**Installation Description:**
Kansas City Power & Light - Montrose Generating Station is an electric energy generating station located in Clinton, Missouri. Equipment at the installation includes three coal-fired boilers, coal and fly ash handling equipment, miscellaneous combustion equipment, and storage tanks.

The installation is an existing major source of particulate matter less than ten microns ($PM_{10}$), sulfur oxides ($SO_X$), nitrogen oxides ($NO_X$), volatile organic compounds (VOC), carbon monoxide (CO) and hazardous air pollutants (HAP).

SEP 2 9 2006
Effective Date

Director or Designee
Department of Natural Resources

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# I. Installation Description and Equipment Listing

## INSTALLATION DESCRIPTION

Kansas City Power & Light - Montrose Generating Station is an electric energy generating station located in Clinton, Missouri. Equipment at the installation includes three coal-fired boilers, coal and fly ash handling equipment, miscellaneous combustion equipment, and storage tanks.

The installation is an existing major source of particulate matter less than ten microns ($PM_{10}$), sulfur oxides ($SO_X$), nitrogen oxides ($NO_X$), volatile organic compounds (VOC), carbon monoxide (CO) and hazardous air pollutants (HAP).

| Reported Air Pollutant Emissions, tons per year | | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | Particulate Matter ≤ Ten Microns (PM-10) | Sulfur Oxides ($SO_x$) | Nitrogen Oxides ($NO_x$) | Volatile Organic Compounds (VOC) | Carbon Monoxide (CO) | Lead (Pb) | Hazardous Air Pollutants (HAP) |
| 2004 | 322.60 | 17177.15 | 6104.41 | 58.89 | 492.43 | 0.11 | 83.19 |
| 2003 | 287.28 | 15722.69 | 5113.47 | 51.17 | 426.73 | 0.10 | 71.93 |
| 2002 | 289.66 | 15825.42 | 5630.37 | 51.57 | 429.51 | 0.11 | 58.89 |
| 2001 | 280.85 | 15173.42 | 5952.98 | 52.94 | 440.72 | 0.35 | 52.62 |
| 2000 | 254.41 | 9516.84 | 5643.62 | 52.75 | 439.69 | 0.10 | 52.54 |

## EMISSION UNITS WITH LIMITATIONS

The following list provides a description of the equipment at this installation which emits air pollutants and which is identified as having unit-specific emission limitations.

| Emission Unit # | Description of Emission Unit | 2004 EIQ EP# |
|---|---|---|
| EU0010 | Rotary Coal Car Dumper | EP-01 |
| EU0020 | Rotary Coal Car Dumper Conveyor | EP-01 |
| EU0030 | Coal Transfer and Conveying | EP-03 |
| EU0040 | Fly Ash Silo Unloading to Trucks | EP-09, EP-10, and EP-11 |
| EU0050 | Boiler #1 | EP-06 |
| EU0060 | Boiler #2 | EP-07 |
| EU0070 | Boiler #3 | EP-08 |
| EU0080 | Emergency Fire Pump Engine | EP-19 |
| EU0090 | Emergency Generator | EP-220 |

## EMISSION UNITS WITHOUT LIMITATIONS

The following list provides a description of the equipment that does not have unit specific limitations at the time of permit issuance.

| Description of Emission Source | 2004 EIQ EP# |
|---|---|
| Coal storage piles | EP-02 |
| Coal crusher (inoperable) | EP-04 |
| One 1,000,000-gallon fuel oil storage tank, installed pre 1970's | EP-05 |
| Fly ash unloading to open storage pile | EP-12 |

| | |
|---|---|
| Fly ash pile maintenance activities | EP-13 |
| Haul roads | EP-14 |
| Two 40,000-gallon fuel oil storage tanks, installed pre 1970's | EP-15 and EP-16 |
| One 10,000-gallon used oil tank | EP-48 |
| One 2,000-gallon split diesel/gasoline storage tank | EP-202, EP-203, and EP-204 |
| One 400-gallon diesel tank for emergency generator | EP-221 |
| One 300-gallon diesel tank for portable pump | EP-214 |
| One 250-gallon gasoline tank for vehicle use | EP-209 |
| Two 240-gallon gasoline tanks, one for fire pump and one for Tainter gate engine | EP-18 and EP-63 |
| Solvent parts cleaner/degreaser | EP-43, EP-61, and EP-205 |
| Backup engine for Tainter gate (0.5 MMBtu/hr) | EP-64 |
| Fly ash silo vents | EP-94, EP-95, EP-96, EP-105, and two others |
| Portable pump, maintenance | EP-206 |
| Portable heating units | EP-207 |
| Painting, maintenance | EP-208 |
| Sand blasting, maintenance | EP-210 |

**DOCUMENTS INCORPORATED BY REFERENCE**

These documents have been incorporated by reference into this permit.

1) Construction Permit 0296-004
2) Construction Permit 0699-008

# II. Plant Wide Emission Limitations

The installation shall comply with each of the following emission limitations. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued.

None.

# III. Emission Unit Specific Emission Limitations

The installation shall comply with each of the following emission limitations. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued.

| EU0010 AND EU0020 – ROTARY COAL CAR DUMPER AND CONVEYOR | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0010 | Rotary coal car dumper; MHDR 3000 ton/hr; installed 1996 | Heyl & Patterson, Inc | EP-01 |
| EU0020 | Conveying coal from rotary car dumper to storage piles; MHDR 3000 ton/hr; installed 1996 | Heyl & Patterson, Inc | EP-03 |

**PERMIT CONDITION (EU0010 AND EU0020)-001**
10 CSR 10-6.060 Construction Permits Required
Construction Permit 0296-004, Issued 1/22/1996

***Emission Limitation:***
Kansas City Power & Light Company - Montrose Generating Station, (the "Permittee") shall not emit more than 14.9 tons of particulate matter less than ten microns ($PM_{10}$) from the coal receiving, conveying and stacking operations during any consecutive 12-month period. [Special Condition 1]

***Monitoring/Recordkeeping:***
1) The permittee shall determine compliance with Condition 1 at the end of each calendar month by adding the coal received from the current month to the coal received from the previous consecutive eleven (11) months and calculating $PM_{10}$ emissions using the form provided (see Attachment A) or equivalent. [Special Condition 2]
2) The permittee shall maintain all records required by Condition 2 on-site for five years and make such records available to Department of Natural Resources personnel upon request. [Special Condition 3]

***Reporting:***
The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102 no later than ten days after the end of the month, if the 12-month cumulative total (Condition 3) records show that the source exceeded the limitation of Condition 1 (14.9 tons $PM_{10}$). [Special Condition 4]

**PERMIT CONDITION (EU0010 AND EU0020)-002**
10 CSR 10-6.060 Construction Permits Required
Construction Permit 0296-004, Issued 1/22/1996

***Emission Limitation:***
If, in the opinion of the director, a continuing situation of demonstrated nuisance odors exists for the neighbors of the facility, the director may require the permittee to submit a corrective action plan

adequate to timely and significantly mitigate the odors. The permittee shall implement any such plan immediately upon its approval by the director. Failure to either submit or implement such a plan shall be a violation of the permit. [Special Condition 5]

***Monitoring/Recordkeeping/Reporting:***
None.

## PERMIT CONDITION (EU0010 AND EU0020)-003
10 CSR 10-6.220 Restriction of Emission of Visible Air Contaminants

***Emission Limitations:***
1) No owner or other person shall cause or permit emissions to be discharged into the atmosphere from any source any visible emissions with an opacity greater than 20%.
2) Exception: A person may discharge into the atmosphere from any source of emissions for a period(s) aggregating not more than six (6) minutes in any 60 minutes air contaminants with an opacity up to 60%.

***Monitoring:***
1) The permittee shall conduct opacity readings on these emission units (EU0010 and EU0020) using the procedures contained in USEPA Test Method 22. At a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by background contrast, ambient lighting, observer position relative to lighting, wind and the presence of uncombined water. Readings are only required when the emission unit is operating and when the weather conditions allow. Each reading shall be for a period of six or more minutes, and the use of multiple stopwatches is not required. If no visible or other significant emissions are observed using these procedures, then no further observations would be required. For emission units with visible emissions perceived or believed to exceed the applicable opacity standard (visible and atypical emissions), the source representative would then conduct a Method 9 observation.
2) The following monitoring schedule must be maintained:
   a) Weekly observations shall be conducted for a minimum of eight consecutive weeks after permit issuance. Should no violation of this regulation be observed during this period then-
   b) Observations must be made once every two weeks for a period of eight weeks. If a violation is noted, monitoring reverts to weekly. Should no violation of this regulation be observed during this period then -
   c) Observations must be made semi-annually. If a violation is noted, monitoring reverts to weekly.

   If the source reverts to weekly monitoring at any time, monitoring frequency will progress in an identical manner from the initial monitoring frequency. If the source has already performed the weekly and biweekly monitoring and is doing monitoring in compliance with a previous permit, the weekly and biweekly monitoring do not need to be repeated.

***Recordkeeping:***
1) The permittee shall maintain records of all observation results (see Attachment B), noting:
   a) Whether any air emissions (except for water vapor) were visible from the emission units,
   b) All emission units from which visible emissions occurred, and
   c) Whether the visible emissions were normal for the process.
2) The permittee shall maintain records of any equipment malfunctions. (see Attachment C)

3) The permittee shall maintain records of any Method 9 test performed in accordance with this permit condition. (see Attachment D)
4) Attachments B, C, and D contain logs including these recordkeeping requirements. These logs, or an equivalent created by the permittee, must be used to certify compliance with this requirement.
5) These records shall be made available to the Missouri Department of Natural Resources' personnel upon request.
6) All records shall be maintained for five years.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after the permittee determined using the Method 9 test that the emission unit(s) exceeded the opacity limit.
2) Reports of any deviations from monitoring, recordkeeping and reporting requirements of this permit condition shall be submitted semiannually, in the semi-annual monitoring report and annual compliance certification, as required by Section V of this permit.

| EU0030 AND EU0040 – COAL TRANSFER AND CONVEYING AND FLY ASH SILO UNLOADING FROM TRUCKS | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0030 | Conveyor belt system for transferring coal; MHDR 600 ton/hr; installed 1958 | United Conveyor Corp. | EP-03 |
| EU0040 | Three places where fly ash is unloaded from silos to either enclosed or open bed trucks using telescoping arms; installed circa 1958 | NA | EP-09, EP-10, and EP-11 |

## PERMIT CONDITION (EU0030 AND EU0040)-001

10 CSR 10-6.220 Restriction of Emission of Visible Air Contaminants

***Emission Limitations:***

1) No owner or other person shall cause or permit emissions to be discharged into the atmosphere from any source any visible emissions with an opacity greater than 40%.
2) Exception: A person may discharge into the atmosphere from any source of emissions for a period(s) aggregating not more than six (6) minutes in any 60 minutes air contaminants with an opacity up to 60%.

***Monitoring:***

1) The permittee shall conduct opacity readings on these emission units (EU0030 and EU0040) using the procedures contained in USEPA Test Method 22. At a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by background contrast, ambient lighting, observer position relative to lighting, wind and the presence of uncombined water. Readings are only required when the emission unit is operating and when the weather conditions allow. Each reading shall be for a period of six or more minutes, and the use of multiple stopwatches is not required. If no visible or other significant emissions are observed using these procedures, then no further observations would be required. For emission units with visible emissions perceived or believed to exceed the applicable opacity standard (visible and atypical emissions), the source representative would then conduct a Method 9 observation.

2) The following monitoring schedule must be maintained:
   a) Weekly observations shall be conducted for a minimum of eight consecutive weeks after permit issuance. Should no violation of this regulation be observed during this period then-
   b) Observations must be made once every two weeks for a period of eight weeks. If a violation is noted, monitoring reverts to weekly. Should no violation of this regulation be observed during this period then-
   c) Observations must be made semi-annually. If a violation is noted, monitoring reverts to weekly.

   If the source reverts to weekly monitoring at any time, monitoring frequency will progress in an identical manner from the initial monitoring frequency. If the source has already performed the weekly and biweekly monitoring and is doing monitoring in compliance with a previous permit, the weekly and biweekly monitoring do not need to be repeated.

***Recordkeeping:***

1) The permittee shall maintain records of all observation results (see Attachment B), noting:
   a) Whether any air emissions (except for water vapor) were visible from the emission units,
   b) All emission units from which visible emissions occurred, and
   c) Whether the visible emissions were normal for the process.
2) The permittee shall maintain records of any equipment malfunctions. (see Attachment C)
3) The permittee shall maintain records of any Method 9 test performed in accordance with this permit condition. (see Attachment D)
4) Attachments B, C, and D contain logs including these recordkeeping requirements. These logs, or an equivalent created by the permittee, must be used to certify compliance with this requirement.
5) These records shall be made available to the Missouri Department of Natural Resources' personnel upon request.
6) All records shall be maintained for five years.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after the permittee determined using the Method 9 test that the emission unit(s) exceeded the opacity limit.
2) Reports of any deviations from monitoring, recordkeeping and reporting requirements of this permit condition shall be submitted semiannually, in the semi-annual monitoring report and annual compliance certification, as required by Section V of this permit.

| EU0050 THROUGH EU0070 - BOILERS | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/ Model # | 2004 EIQ Reference # |
| EU0050 | Boiler #1, dry bottom, tangential-fired boiler; primary fuel - coal; start-up fuel - #2 fuel oil, petroleum coke, supplemental fuel – clean biomass such as switch grass; MHDR 1668 MMBtu/hr; equipped with dedicated electrostatic precipitator (ESP) to control PM ; installed 1958 | Combustion Engineering | EP-06 |
| EU0060 | Boiler #2, dry bottom, tangential-fired boiler; primary fuel - coal; start-up fuel - #2 fuel oil, petroleum coke, supplemental fuel – clean biomass such as switch grass; MHDR 1668 MMBtu/hr; equipped with dedicated electrostatic precipitator (ESP) to control PM; exhausts to common stack with EU0070; installed 1960 | Combustion Engineering | EP-07 |
| EU0070 | Boiler #3, dry bottom, tangential-fired boiler; primary fuel - coal; start-up fuel - #2 fuel oil, petroleum coke, used oil, supplemental fuel – clean biomass such as switch grass; MHDR 1640 MMBtu/hr; equipped with dedicated electrostatic precipitator (ESP) to control PM; exhausts to common stack with EU0060; installed 1964 | Combustion Engineering | EP-08 |

## PERMIT CONDITION (EU0050 THROUGH EU0070)-001

10 CSR 10-3.060 Maximum Allowable Emissions of Particulate Matter from Fuel Burning Equipment Used for Indirect Heating and 40 CFR Part 64 Compliance Assurance Monitoring

Note: Compliance Assurance Monitoring (CAM) applies to these units, so this permit condition incorporates parts of 40 CFR Part 64 and, through that, parts of 40 CFR Part 60. However, the Department of Natural Resources, Air Pollution Control Program, Compliance/Enforcement Section has approved a CAM plan and CAM test plan for these units. Where conflicts arise between these documents and 40 CFR Part 60, the CAM plan and CAM test plan govern. This will assure that where there is doubt, the acceptance criteria in the CAM plan and CAM test plan will be used, and not those in 40 CFR Part 60 Appendix B Performance Specification 11 (PS-11). These monitors are indicators of compliance, and not compliance monitors. The full PS-11 requirements do not apply to monitors that are only indicators of compliance.

***Emission Limitations:***

1) The permittee shall not emit particulate matter in excess of 0.20 lb/MMBtu.
2) This emission rate was calculated using the following equation:
   For existing indirect heating sources:
   $E = 0.90(Q)^{-0.174}$
   Where:
   E = the maximum allowable particulate emission rate in pounds per million Btu of heat input, rounded off to two decimal places; and
   Q = the installation heat input in millions of Btu per hour (1668 MMBtu/hr + 1668 MMBtu/hr + 1640 MMBtu/hr = 4976 MMBtu/hr).
3) Per 40 CFR §60.8(c), emissions in excess of the level of the emission limit in 1) above during periods of startup, shutdown, and malfunction shall not be considered a violation.

***Monitoring:***

1) The permittee shall install, calibrate, maintain and operate a PM continuous emission monitoring system (CEMS) in each stack in order to provide a reasonable assurance of the performance of the electrostatic precipitators (ESPs) in accordance with §60.13 and Appendix B of 40 CFR Part 60.
2) Each PM CEMS shall be installed such that representative measurements of emissions are obtained and problems due to any detected flow disturbances or varying PM stratification are minimized. Prior to installation, measurements shall be made of flow dynamics and/or particulate matter to determine the existence or extent of PM stratification. Additional procedures for location of PM CEMS contained in Performance Specialization 11 (PS-11) of Appendix B to Part 60 shall be used.
3) All PM CEMS shall be installed and operational prior to conduction of any performance tests. The permittee shall perform verification procedures to confirm the operational status of the PM CEMS prior to the required monitoring start. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device.
4) The permittee shall establish the indicator range as the hourly average PM CEMS reading covering the full range of measurements made during the initial calibration testing plus 25%. This indicator range shall be a calibrated instrument output and shall reflect reasonable assurance of the proper operation and maintenance of the electrostatic precipitators (ESPs).
5) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including calibration checks and zero and span adjustments), each PM CEMS shall be in continuous operation and required sampling frequency shall be in accordance with §64.13(e)(2). Each PM CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
6) Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for data averages and calculations, or fulfilling a minimum data availability requirement. The permittee shall use all the data collected during all other periods in assessing the operation of the ESPs and associated monitoring system.
7) The permittee shall reduce all data to one-hour averages. One-hour averages shall be computed from four or more data points equally spaced over each one-hour period.
8) Results shall be recorded on an automated Data Acquisition Handling System (DAHS) as follows:
   a) Record the analog output of the PM CEMS;
   b) Calculate emissions values, in lb/MMBtu, and according to the correlation(s) established during the PM CEMS calibration;
   c) Store the hourly averages of the calculated emissions values;
   d) Record the daily zero-span calibration results;
   e) Initiate an alarm if any daily zero or span value exceeds the error limit of plus or minus 5%;
   f) Exceedances - initiate an alarm if the hourly averaged PM CEMS emission value reaches or exceeds the lower of the following limits:
      i) A value equivalent to 1.25 times the highest PM CEMS response value reached during the correlation tests, or
      ii) A value equivalent to 0.9 times the source emission limit; and,
   g) Initiate an alarm on the occurrence of a malfunction status indicator from the PM CEMS.
9) Upon detecting an exceedance, the permittee shall restore operation of EU0050 through EU0070 (including the ESPs and associated capture system) to their normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or

malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Operational checks shall be made as soon as practicable and may include:

a) ESP field checks (T/R voltage, current, spark rate);
b) Visual inspection of control equipment;
c) Unusual fuel characteristics; and,
d) Boiler upset conditions.

10) Quality Assurance and Control Practices (QA/QC)
   a) Factory supplied filter standards will be used to calibrate the instruments at a reference zero and upscale span value. These calibration standards will be maintained in accordance with manufacturer's recommendations. Following the calibration an internal zero-span cycle will be initiated, thus establishing initial values for future reference.
   b) Daily zero-span cycles will be performed with the results stored in the data system and compared with the initial values.
   c) Should either the zero or span value error exceed plus or minus 5% of the starting value, an alarm will be initiated and the permittee shall recalibrate the instrument to the factory standards.
   d) A quarterly reference calibration will be performed as described in the instrument operations manual. The factory standards will be used to measure instrument response at a zero and upscale value. Should either of these readings exceed the factory standard by more than plus or minus 5% of the full-scale measurement range, the instrument will be reset to the factory standard values.
   e) Routine scheduled maintenance procedures will be established in accordance with manufacturer's recommendations.
11) If the accumulation of exceedances or excursions exceeds 5% of operating time for a reporting period, the permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the permittee shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:
   a) Improved preventive maintenance practices;
   b) Process operation changes;
   c) Appropriate improvements to control methods;
   d) Other steps appropriate to correct control performance;
   e) More frequent or improved monitoring.
12) The permittee shall begin the monitoring required under this permit condition within 180 days after the approval of the Part 70 renewal operating permit.
13) The permittee shall maintain monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment, at all times.

***Testing:***

1) The instruments shall be calibrated based on the boiler load, coal, and ESPs characteristics and any other performance or test data deemed applicable by the permittee and/or director. Reference method measurements will be conducted in accordance with accepted method standards (EPA Methods 5 or 17) and compared with the integrated (arithmetic average) PM CEMS output over the reference method test period.

2) Correlation/Performance Testing
   a) The PM CEMS shall be initially operated for a period of approximately 30 days under various operating conditions to identify condition necessary to produce three target concentration levels for the correlation testing. During the 30 day pre-test monitoring period the following key operating parameters will be recorded on each stack:
      i) Monitor output;
      ii) Plant load;
      iii) ESP voltage and current readings.
   b) A minimum of nine valid runs (e.g. 3 PM concentration loads and 3 tests per condition) will be used to obtain the correlation loads equation and correlation coefficient on each stack. A run will be declared "not valid" only when performed during a time when conditions are clearly not representative of normal operation, including periods of startup, shutdown and malfunction.
   c) The linear correlation equation, which gives the predicted PM concentration as a function of the monitors response will be calculated according to Equation 11-3 of Performance Specification 11 of Appendix B to Part 60. The linear correlation coefficient will be calculated according to Equation 11-14 of Performance Specification 11 of Appendix B to Part 60.
   d) Tests will be performed at three different PM concentration levels with a minimum of three tests at each level, if possible. Level 1 encompasses the range 0% to 50% of the maximum PM concentration available. Level 2 should range from 50% to 75% of the maximum concentration, and Level 3 should range from 75% to 100% of the maximum concentration. The source should be operated over the complete range of expected conditions, so as to assure that the data produced is representative. The data gathered during the 30-day pre-test monitoring period shall be used to produce the desired concentrations for the test runs of each stack.
   e) During correlation testing, the reference method data and PM CEMS measurements will be converted into units of pounds PM per MMBtu to establish limits comparable to the emission limitation of 0.20 lb PM/MMBtu. Once established, these limits will be converted into units of pounds PM per actual stack gas volume, or pounds of PM per megawatt. During operation after testing, the PM CEMS output and determination of PM levels with respect to limits, will be conducted only in units of pounds per actual stack gas volume or pounds PM per megawatt.
   f) The correlation coefficient (r) for each stack resulting from the calibration testing must be greater than or equal to 0.75.
   g) Once the correlation equation has been determined for each stack, it will be applied to the PM CEMS data collected by the Data Recorder.

***Recordkeeping:***

1) The permittee shall comply with the recordkeeping requirements specified in §70.6(a)(3)(ii) including records of required monitoring information that include the following:
   a) The date, place, and time of sampling or measurements;
   b) The date(s) analyses were performed;
   c) If applicable, the company or entity that performed the analyses;
   d) The analytical techniques or methods used;
   e) The results of such analyses; and
   f) The operating conditions as existing at the time of sampling or measurement;
   g) Retention of records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all required calibration and maintenance records and all original

strip-chart recordings for continuous monitoring instrumentation, and copies of all required reports (including any written Quality Improvement Plan (QIP)).

2) The permittee may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, instead of paper provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.
3) Following any exceedance, the permittee shall record that operations returned to normal without operator action, or any necessary follow-up actions to return operation to within the indicator range.
4) These records shall be made available immediately for inspection to the Department of Natural Resources' personnel upon request.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102 no later than ten days after any deviations/exceedances of this permit condition.
2) Performance Testing
   a) The permittee shall submit operating parameter data obtained during the conduct of any applicable compliance or performance tests.
   b) The permittee shall submit documentation that no changes to the emission units, including the control device and capture system, have taken place that could result in a significant change in the control system performance or selected indicator ranges since the last performance or compliance test.
3) If the permittee identifies a failure to achieve compliance with the PM emissions limit for which the PM CEMS did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges, the permittee shall promptly notify the MDNR and, if necessary, submit a proposed modification to the Part 70 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
4) The permittee shall submit quarterly monitoring reports certified by a responsible official. The monitoring report shall include, as a minimum, the following information, as applicable:
   a) All instances of deviations from permit requirements must be clearly identified.
   b) Prompt reporting of deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken.
   c) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   d) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   e) A description of the actions taken to implement a QIP during the reporting period as specified in §64.8. Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

## PERMIT CONDITION (EU0050 THROUGH EU0070)-002

10 CSR 10-6.220 Restriction of Emission of Visible Air Contaminants

***Emission Limitations:***

1) No owner or other person shall cause or permit emissions to be discharged into the atmosphere from any existing source any visible emissions with an opacity greater than 40%.
2) Exception: A person may discharge into the atmosphere from any source of emissions for a period(s) aggregating not more than six (6) minutes in any 60 minutes air contaminants with an opacity up to 60%.

***Monitoring/Operational Requirements:***

1) A continuous opacity monitoring system shall be installed, calibrated, maintained, and operated in accordance with 40 CFR Part 60, Appendix B - Performance Specification 1.
2) COMS General Requirements
   a) Source operating time includes any time fuel is being combusted and/or a fan is being operated.
   b) Cycling times include the total time a monitoring system requires to sample, analyze and record an emission measurement. Continuous monitoring systems for measuring opacity shall complete a minimum of one cycle of operating (sampling and analyzing) for each successive ten-second period and one cycle of data recording for each successive six-minute period.
   c) Each COMS shall be certified by the director of the Air Pollution Control Program after review and acceptance of a demonstration of conformance with 40 CFR Part 60, Appendix B - Performance Specification 1.
   d) Each COMS shall be subject to audits conducted by the department, and all COMS records shall be made available upon request to department personnel.

***Recordkeeping:***

1) The permittee shall maintain a file (hard copy or electronic version) of the following information for a minimum of five years from the date the data was collected:
   a) All information reported in the quarterly summaries including:
      i) The charts or printouts generated by the COMS, where applicable;
      ii) An opacity summary report;
      iii) An excess opacity emission summary;
      iv) An excess opacity emission summary list;
      v) An opacity monitoring downtime summary lit; and
   b) All six-minute opacity averages and daily Quality Assurance (QA)/Quality Control (QC) records. This includes, but is not restricted to the daily monitoring system calibration check done on the continuous opacity monitoring system.
2) The permittee shall maintain records of any opacity monitoring equipment malfunctions.
3) The permittee shall maintain records of any Method 9 test performed in accordance with this permit condition. Attachment D or equivalent recordkeeping form shall be used to provide Method 9 Visual Observation log records.
4) These records shall be made available immediately for inspection to the Department of Natural Resources' personnel upon request. All records must be maintained for five years.

***Reporting:***

1) The permittee shall report to the Air Pollution Control Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, no later than ten days after any deviations/exceedances of this permit condition.
2) The permittee shall submit a quarterly written report to the director of the Air Pollution Control Program. All quarterly reports shall be postmarked no later than the thirtieth day following the end of each calendar quarter and shall included the following emissions data:
   a) A summary including total time for each cause of excess emissions and/or monitor downtime;
   b) Nature and cause of excess emissions, if known;
   c) The six-minute average opacity values greater than the opacity emission requirements (the average of the values shall be obtained by using the procedures specified in the Reference Method used to determine the opacity of the visible emissions);
   d) The date and time identifying each period during which the COMS was inoperative (except for zero and span checks), including the nature and frequency of system repairs or adjustments that were made during these times; and
   e) If no excess emissions have occurred during the reporting period and the COMS has not been inoperative, repaired or adjusted, this information shall be stated in the report.

## PERMIT CONDITION (EU0050 THROUGH EU0070)-003

10 CSR 10-6.260 Restriction of Emission of Sulfur Compounds

Note: Table 1 in 10 CSR 10-6.260 in the Missouri State Implementation Plan (SIP) and the related September 30, 1988 state consent agreement with Kansas City Power & Light (KPL&L) specified an emission limitation of 12.9 lb $SO_2$/MMBtu averaged over three hours. In the 8/31/05 revision to 10 CSR 10-6.260, Missouri DNR, with KCP&L's agreement, changed this to 1.3 lb $SO_2$/MMBtum averaged over a year. The United States Environmental Protection Agency (EPA) disapproved this on October 3, 2005. Therefore, at the time of this permit's issuance, the prior requirement of 12.9 lb $SO_2$/MMBtu averaged over three hours remains federally enforceable, while the changed requirement of 1.3 lb lb $SO_2$/MMBtu averaged over a year is state enforceable. The EPA, Missouri DNR, and KCP&L have all agreed to change the SIP and consent agreement to 3.9 lb $SO_2$/MMBtu, averaged over a midnight-to-midnight twenty-four-hour time period. When this new requirement (c) goes into effect, it will become the only requirement, and the previous two requirements (a) and (b) will no longer be enforceable and should be considered dropped from this permit.

***Emission Limitations: ****

1) Kansas City Power & Light Company - Montrose Generating Station shall limit their average sulfur dioxide ($SO_2$) emissions per million Btus actual heat input into the atmosphere to:
   a) 12.9 pounds in any consecutive three (3)-hour period until Table 1 in 10 CSR 20-6.260 in the Missouri State Implementation Plan is modified;
   b) 1.3 pounds annually until Table 1 in 10 CSR 20-6.260 in the Missouri State Implementation Plan is modified; and
   c) 3.9 pounds in any midnight-to-midnight twenty-four (24) time period thereafter.
2) No person shall cause or permit the emission of sulfur compounds from any source which causes or contributes to concentrations exceeding those specified in 10 CSR 10-6.010 Ambient Air Quality Standards.

| Pollutant | Concentration by Volume | Remarks |
|---|---|---|
| Sulfur Dioxide ($SO_2$) | 0.03 parts per million (ppm) (80 micrograms per cubic meter ($\mu g/m^3$)) | Annual arithmetic mean |
| | 0.14 ppm (365 $\mu g/m^3$) | 24-hour average not to be exceeded more than once per year |
| | 0.5 ppm (1300 $\mu g/m^3$) | 3-hour average not to be exceeded more than once per year |
| Hydrogen Sulfide ($H_2S$) | 0.05 ppm (70 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times per year |
| | 0.03 ppm (42 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times in any 5 consecutive days |
| Sulfuric Acid ($H_2SO_4$) | 10 $\mu g/m^3$ | 24-hour average not to be exceeded more than once in any 90 consecutive days |
| | 30 $\mu g/m^3$ | 1-hour average not to be exceeded more than once in any 2 consecutive days |

***Monitoring:***

1) The permittee shall maintain and operate a continuous emission monitoring system (CEMS) in accordance with all the requirements of 40 CFR Part 75 to monitor $SO_2$ emissions. Results shall be recorded on an automated Data Acquisition Handling System (DAHS).
2) The permittee shall ensure that each CEMS meets the equipment, installation, and performance specifications in Appendix A to 40 CFR Part 75; and is maintained according to the quality assurance and quality control procedures in Appendix B to 40 CFR Part 75.
3) The permittee shall ensure that all CEMS are in operation and monitoring unit emissions at all times that the affected unit, EU0050 through EU0070, combusts any fuel except during periods of calibration, quality assurance, or preventative maintenance, as well as, periods of repair, periods of backups of data from the DAHS or recertification.
4) The permittee shall ensure that each CEMS is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. The permittee shall reduce all $SO_2$ emissions data to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance, or backups of data from the DAHS, or recertification. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.
5) The permittee shall prepare and maintain a monitoring plan in accordance with §75.53. A monitoring plan shall contain sufficient information on the CEMS to demonstrate that all unit $SO_2$ emissions are monitored and reported.
6) Whenever the permittee makes a replacement, modification, or change in the certified CEMS, including a change in the automated DAHS or in the flue gas handling system, that affects information reported in the monitoring, then the permittee shall update the monitoring plan, by the applicable deadline specified in §75.62.

***Recordkeeping:***

1) The permittee shall maintain a file on-site of all measurements, data, reports, and other information required by §75.53, §75.57 and §75.59. Records include the following:
   a) Total fuel consumed during the control period;
   b) The total heat input for each emissions unit during the control period;
   c) Reports of all stack testing conducted;
   d) All other data collected by a CEMS necessary to convert the monitoring data to the units of the applicable emission limitation;
   e) All performance evaluations conducted in the past year;
   f) All monitoring device calibration checks;
   g) All monitoring system, monitoring device and performance testing measurements;
   h) Records of adjustments and maintenance performed on monitoring systems and devices; and
   i) A log identifying each period during which the CEMS or alternate procedure was inoperative, except for zero and span checks, and the nature of the repairs and adjustments performed to make the system operative.
2) All records shall be kept in a form suitable for inspection for at least five years and be made available immediately to the Department of Natural Resources' personnel upon request.

***Reporting:***

1) The permittee shall submit all quarterly reports required by 40 CFR Part 75. The permittee shall submit these reports to the Environmental Protection Agency (EPA) by direct computer-to-computer electronic transfer via EPA-provided software. These reports are due within 30 days after the end of each calendar quarter. The quarterly reports must include the following essential information:
   a) Facility information in accordance with §75.64(a)(1);
   b) Hourly and cumulative emissions data;
   c) Hourly unit operating information (e.g., load, heat input rate, operating time, etc.);
   d) Monitoring plan information;
   e) Results of required quality assurance tests (e.g., daily calibrations, linearity checks, RATAs, etc.); and
   f) Certification statements from the Designated Representative or Authorized Account Representative (or the Alternate Representative), attesting to the completeness and accuracy of the data.
2) The permittee shall submit the electronic quarterly reports only to the EPA, not to the Missouri Department of Natural Resources. However, the permittee shall report to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102 no later than ten days after any deviation from the monitoring or reporting requirements of this permit condition.

## PERMIT CONDITION (EU0050 THROUGH EU0070)-004

10 CSR 10-6.270 Acid Rain Source Permits Required

***Emission Limitation:***

The permittee shall obtain an Acid Rain Source Permit for EU0050 through EU0070 pursuant to Title IV of the Clean Air Act.

A Phase II permit (Missouri Department of Natural Resources project 1998-09-049, ORIS Code 2080) was issued to the permittee on January 22, 1999, with effective dates from January 1, 2000 to December 31, 2004. Sulfur dioxide ($SO_2$) limitations are referenced in this existing Title IV: Phase II Acid Rain Permit for the installation. The permittee submitted a renewal application on September 4, 2004, under 10 CSR 10-6.270, "Acid Rain Source Permits Required." No changes to the installation's status were reflected in this renewal application.

***Monitoring/Recordkeeping:***

The permittee shall retain the most current acid rain permit issued to this installation on-site and shall immediately make such permit available to any Missouri Department of Natural Resources' personnel upon request.

***Reporting:***

Annual Compliance Certification

## PERMIT CONDITION (EU0050 THROUGH EU0070)-005

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

***Emission Limitations:***

1) The permittee shall limit emissions of $NO_X$ to the rate of 0.35 lbs. $NO_X$ /million British thermal units (MMBtu) of heat input during the control period (the period beginning May 1 of a calendar year and ending on September 30 of the same calendar year.)
2) In lieu of complying with the above emission limit, the permittee may comply through the $NO_X$ emissions trading program under 10 CSR 10-6.350(3)(B).
   a) Compliance with this rule shall not relieve the permittee of the responsibility to comply fully with applicable provisions of the Air Conservation Law and rules or any other requirements under local, state or federal law. Specifically, compliance with 10 CSR 10-6.350 shall not violate the permit conditions previously established under 10 CSR 10-6.060 or 10 CSR 10-6.065.

***Monitoring:***

1) Compliance shall be measured during the control period.
2) All valid data shall be used for calculating $NO_X$ emissions rates.
3) Any coal-affected unit shall install, certify, operate, maintain, and quality assure a $NO_X$ and diluent CEMS pursuant to the requirements in 40 CFR Part 75;

***Recordkeeping:***

1) The permittee shall maintain records of the following:
   a) Total fuel consumed during the control period;
   b) The total heat input for each emissions unit during the control period;
   c) Reports of all stack testing conducted to meet the requirements of this rule;
   d) All other data collected by a CEMS necessary to convert the monitoring data to the units of the applicable emission limitation;
   e) All performance evaluations conducted in the past year;
   f) All monitoring device calibration checks;
   g) All monitoring system, monitoring device and performance testing measurements;
   h) Records of adjustments and maintenance performed on monitoring systems and devices; and
   i) A log identifying each period during which the CEMS or alternate procedure was inoperative, except for zero and span checks, and the nature of the repairs and adjustments performed to make the system operative.
2) All records must be kept on-site for a period of five years and made available to the department upon request.

***Reporting***:

1) A compliance certification report for each affected unit shall be submitted to the department by October 31 following each control period. The report shall include:
   a) The owner and operator;
   b) The $NO_X$ authorized account representative;
   c) $NO_X$ unit name, compliance and overdraft account numbers;
   d) $NO_X$ emission rate limitation (lb/MMBtu);
   e) Actual $NO_X$ emission rate (lb/MMBtu) for the control period;

f) Actual heat input (MMBtu) for the control period. The unit's total heat input for the control period in each year will be determined in accordance with the test methods and monitoring requirements;
g) Actual $NO_X$ mass emissions (tons) for the control period.

2) The $NO_X$ authorized account representatives seeking the recording of a $NO_X$ allowance transfer shall submit the transfer request to the director. To be considered correctly submitted, the $NO_X$ allowance transfer shall include the following elements in a format specified by the director:
   a) The numbers identifying both the transferor and transferee accounts;
   b) A specification by serial number of each $NO_X$ allowance to be transferred; and
   c) The printed name and signature of the $NO_X$ authorized account representative of the transferor account and the date signed.
3) Any unit with valid CEMS data for the control period must use that data to determine compliance with the provisions of 10 CSR 10-6.350.
4) The permittee shall report any deviations/exceedances of this permit condition using the semi-annual monitoring report and annual compliance certification to the Air Pollution Control Program Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as required by 10 CSR 10-6.065(6)(C)1.C.(III).

| EU0080 AND EU0090 – EMERGENCY EQUIPMENT | | | |
|---|---|---|---|
| Emission Unit | Description | Manufacturer/Model # | 2004 EIQ Reference # |
| EU0080 | Internal combustion engine; diesel fired, MHDR 1.01 MMBtu/hr (400 HP); installed 1993 | NA | NA |
| EU0090 | Emergency generator rate at 180 KVA; powered by 250 HP (1.75 MMBtu) internal combustion engine; diesel powered; installed 1999 | Generator - Kohler, IC Engine - John Deere/ 180ROZJ | NA |

## PERMIT CONDITION (EU0080 AND EU0090)-001

10 CSR 10-6.260 Restriction of Emission of Sulfur Compounds

***Emission Limitations:***

1) Emissions from EU0080 and EU0090 shall not contain more than five hundred parts per million by volume (500 ppmv) of sulfur dioxide.
2) Stack gasses shall not contain more than thirty-five milligrams (35 mg) per cubic meter of sulfuric acid or sulfur trioxide or any combination of those gases averaged on any consecutive three hour time period.
3) No person shall cause or permit the emission of sulfur compounds from any source which causes or contributes to concentrations exceeding those specified in 10 CSR 10-6.010 Ambient Air Quality Standards.

| Pollutant | Concentration by Volume | Remarks |
|---|---|---|
| Sulfur Dioxide ($SO_2$) * | 0.03 parts per million (ppm) (80 micrograms per cubic meter ($\mu g/m^3$)) | Annual arithmetic mean |
| | 0.14 ppm (365 $\mu g/m^3$) | 24-hour average not to be exceeded more than once per year |
| | 0.5 ppm (1300 $\mu g/m^3$) | 3-hour average not to be exceeded more than once per year |
| Hydrogen Sulfide ($H_2S$) | 0.05 ppm (70 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times per year |
| | 0.03 ppm (42 $\mu g/m^3$) | ½-hour average not to be exceeded over 2 times in any 5 consecutive days |
| Sulfuric Acid ($H_2SO_4$) | 10 $\mu g/m^3$ | 24-hour average not to be exceeded more than once in any 90 consecutive days |
| | 30 $\mu g/m^3$ | 1-hour average not to be exceeded more than once in any 2 consecutive days |

***Monitoring/Recordkeeping/Reporting:***
The permittee will always be in compliance with this regulation. Calculations demonstrating compliance are in Attachment E. The permittee shall keep this attachment with this permit. No monitoring or reporting is required for this permit condition.

# IV. Core Permit Requirements

The installation shall comply with each of the following requirements. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued.

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

1) In the event of a malfunction, which results in excess emissions that exceed one hour, the permittee shall submit to the director within two business days, in writing, the following information:
   a) Name and location of installation;
   b) Name and telephone number of person responsible for the installation;
   c) Name of the person who first discovered the malfunction and precise time and date that the malfunction was discovered.
   d) Identity of the equipment causing the excess emissions;
   e) Time and duration of the period of excess emissions;
   f) Cause of the excess emissions;
   g) Air pollutants involved;
   h) Best estimate of the magnitude of the excess emissions expressed in the units of the applicable requirement and the operating data and calculations used in estimating the magnitude;
   i) Measures taken to mitigate the extent and duration of the excess emissions; and
   j) Measures taken to remedy the situation that caused the excess emissions and the measures taken or planned to prevent the recurrence of these situations.
2) The permittee shall submit the paragraph 1 information list to the director in writing at least ten days prior to any maintenance, start-up or shutdown, which is expected to cause an excessive release of emissions that exceed one hour. If notice of the event cannot be given ten days prior to the planned occurrence, it shall be given as soon as practicable prior to the release. If an unplanned excess release of emissions exceeding one hour occurs during maintenance, start-up or shutdown, the director shall be notified verbally or by facsimile machine (fax) transmission as soon as practical during normal working hours and no later than the close of business of the following working day. If notice is given verbally, then a written notice shall follow within ten working days. If notice is given by fax and this fax contains all the relevant information, then the permittee need not submit written notice, but shall maintain a copy of the material submitted by fax and documentation that the fax transmission was successful
3) Upon receipt of a notice of excess emissions issued by an agency holding a certificate of authority under section 643.140, RSMo, the permittee may provide information showing that the excess emissions were the consequence of a malfunction, start-up or shutdown. The information, at a minimum, should be the paragraph 1 list and shall be submitted not later than 15 days after receipt of the notice of excess emissions. Based upon information submitted by the permittee or any other pertinent information available, the director or the commission shall make a determination whether the excess emissions constitute a malfunction, start-up or shutdown and whether the nature, extent and duration of the excess emissions warrant enforcement action under section 643.080 or 643.151, RSMo.
4) Nothing in this rule shall be construed to limit the authority of the director or commission to take appropriate action, under sections 643.080, 643.090 and 643.151, RSMo to enforce the provisions of the Air Conservation Law and the corresponding rule.

5) Compliance with this rule does not automatically absolve the permittee of liability for the excess emissions reported.

**10 CSR 10-6.060 Construction Permits Required**

The permittee shall not commence construction, modification, or major modification of any installation subject to this rule, begin operation after that construction, modification, or major modification, or begin operation of any installation which has been shut down longer than five years without first obtaining a permit from the permitting authority.

**10 CSR 10-6.065 Operating Permits**

The permittee shall file a complete application for renewal of this operating permit at least six months before the date of permit expiration. In no event shall this time be greater than eighteen months. [10 CSR 10-6.065(6)(B)1.A(V)] The permittee shall retain the most current operating permit issued to this installation on-site. [10 CSR 10-6.065(6)(C)1.C(II)] The permittee shall immediately make such permit available to any Missouri Department of Natural Resources personnel upon request. [10 CSR 10-6.065(6)(C)3.B]

**10 CSR 10-6.110 Submission of Emission Data, Emission Fees and Process Information**

1) The permittee shall complete and submit an Emission Inventory Questionnaire (EIQ) in accordance with the requirements outlined in this rule.
2) The permittee shall pay an annual emission fee per ton of regulated air pollutant emitted according to the schedule in the rule. This fee is an emission fee assessed under authority of RSMo. 643.079 to satisfy the requirements of the Federal Clean Air Act, Title V.
3) The fees shall be due April 1 each year for emissions produced during the previous calendar year. The fees shall be payable to the Department of Natural Resources and shall be accompanied by the Emissions Inventory Questionnaire (EIQ) form or equivalent approved by the director.

**10 CSR 10-6.130 Controlling Emissions During Episodes of High Air Pollution Potential**

This rule specifies the conditions that establish an air pollution alert (yellow/orange/red/purple), or emergency (maroon) and the associated procedures and emission reduction objectives for dealing with each. The permittee shall submit an appropriate emergency plan if required by the Director.

**10 CSR 10-6.150 Circumvention**

The permittee shall not cause or permit the installation or use of any device or any other means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission or air contaminant which violates a rule of the Missouri Air Conservation Commission.

**10 CSR 10-6.170 Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin**

1) The permittee shall not cause or allow to occur any handling, transporting or storing of any material; construction, repair, cleaning or demolition of a building or its appurtenances; construction or use of a road, driveway or open area; or operation of a commercial or industrial installation without applying reasonable measures as may be required to prevent, or in a manner which allows or may allow, fugitive particulate matter emissions to go beyond the premises of origin in quantities that the particulate matter may be found on surfaces beyond the property line of origin. The nature or origin of the particulate matter shall be determined to a reasonable degree of certainty by a technique proven to be accurate and approved by the director.

2) The permittee shall not cause nor allow to occur any fugitive particulate matter emissions to remain visible in the ambient air beyond the property line of origin.
3) Should it be determined that noncompliance has occurred, the director may require reasonable control measures as may be necessary. These measures may include, but are not limited to, the following:
   a) Revision of procedures involving construction, repair, cleaning and demolition of buildings and their appurtenances that produce particulate matter emissions;
   b) Paving or frequent cleaning of roads, driveways and parking lots;
   c) Application of dust-free surfaces;
   d) Application of water; and
   e) Planting and maintenance of vegetative ground cover.

**10 CSR 10-6.180 Measurement of Emissions of Air Contaminants**

1) The director may require any person responsible for the source of emission of air contaminants to make or have made tests to determine the quantity or nature, or both, of emission of air contaminants from the source. The director may specify testing methods to be used in accordance with good professional practice. The director may observe the testing. All tests shall be performed by qualified personnel.
2) The director may conduct tests of emissions of air contaminants from any source. Upon request of the director, the person responsible for the source to be tested shall provide necessary ports in stacks or ducts and other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants.
3) The director shall be given a copy of the test results in writing and signed by the person responsible for the tests.

**10 CSR 10-3.030 Open Burning Restrictions**

1) The permittee shall not conduct, cause, permit or allow a salvage operation, the disposal of trade wastes or burning of refuse by open burning.
2) Exception - Open burning of trade waste or vegetation may be permitted only when it can be shown that open burning is the only feasible method of disposal or an emergency exists which requires open burning.
3) Any person intending to engage in open burning shall file a request to do so with the director. The request shall include the following:
   a) The name, address and telephone number of the person submitting the application; The type of business or activity involved; A description of the proposed equipment and operating practices, the type, quantity and composition of trade wastes and expected composition and amount of air contaminants to be released to the atmosphere where known;
   b) The schedule of burning operations;
   c) The exact location where open burning will be used to dispose of the trade wastes;
   d) Reasons why no method other than open burning is feasible; and
   e) Evidence that the proposed open burning has been approved by the fire control authority which has jurisdiction.
4) Upon approval of the open burning permit application by the director, the person may proceed with the operation under the terms of the open burning permit. Be aware that such approval shall not exempt Kansas City Power & Light – Montrose Generating Station from the provisions of any other law, ordinance or regulation.

5) The permittee shall maintain files with letters from the director approving the open burning operation and previous DNR inspection reports.

**10 CSR 10-3.090 Restriction of Emission of Odors**

No person may cause, permit or allow the emission of odorous matter in concentrations and frequencies or for durations that odor can be perceived when one volume of odorous air is diluted with seven volumes of odor-free air for two separate trials not less than 15 minutes apart within the period of one hour.

**This requirement is not federally enforceable.**

**Title VI – 40 CFR Part 82 Protection of Stratospheric Ozone**

1) The permittee shall comply with the standards for labeling of products using ozone-depleting substances pursuant to 40 CFR Part 82, Subpart E:
   a) All containers in which a class I or class II substance is stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced into interstate commerce pursuant to §82.106.
   b) The placement of the required warning statement must comply with the requirements pursuant to §82.108.
   c) The form of the label bearing the required warning statement must comply with the requirements pursuant to §82.110.
   d) No person may modify, remove, or interfere with the required warning statement except as described in §82.112.
2) The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:
   a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
   b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
   c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
   d) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with recordkeeping requirements pursuant to §82.166. ("MVAC-like" appliance as defined at §82.152).
   e) Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156.
   f) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.
3) If the permittee manufactures, transforms, imports, or exports a class I or class II substance, the permittee is subject to all the requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.
4) If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been

completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or system used on passenger buses using HCFC-22 refrigerant.

The permittee shall be allowed to switch from any ozone-depleting substance to any alternative that is listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G, Significant New Alternatives Policy Program. *Federal Only - 40 CFR Part 82*

**10 CSR 10-6.280 Compliance Monitoring Usage**

1) The permittee is not prohibited from using the following in addition to any specified compliance methods for the purpose of submission of compliance certificates:
   a) Monitoring methods outlined in 40 CFR Part 64;
   b) Monitoring method(s) approved for the permittee pursuant to 10 CSR 10-6.065, "Operating Permits", and incorporated into an operating permit; and
   c) Any other monitoring methods approved by the director.
2) Any credible evidence may be used for the purpose of establishing whether a permittee has violated or is in violation of any such plan or other applicable requirement. Information from the use of the following methods is presumptively credible evidence of whether a violation has occurred by a permittee:
   a) Monitoring methods outlined in 40 CFR Part 64;
   b) A monitoring method approved for the permittee pursuant to 10 CSR 10-6.065, "Operating Permits", and incorporated into an operating permit; and
   c) Compliance test methods specified in the rule cited as the authority for the emission limitations.
3) The following testing, monitoring or information gathering methods are presumptively credible testing, monitoring, or information gathering methods:
   a) Applicable monitoring or testing methods, cited in:
      i) 10 CSR 10-6.030, "Sampling Methods for Air Pollution Sources";
      ii) 10 CSR 10-6.040, "Reference Methods";
      iii) 10 CSR 10-6.070, "New Source Performance Standards";
      iv) 10 CSR 10-6.080, "Emission Standards for Hazardous Air Pollutants"; or
   b) Other testing, monitoring, or information gathering methods, if approved by the director, that produce information comparable to that produced by any method listed above.

# V. General Permit Requirements

The installation shall comply with each of the following requirements. Consult the appropriate sections in the Code of Federal Regulations (CFR) and Code of State Regulations (CSR) for the full text of the applicable requirements. All citations, unless otherwise noted, are to the regulations in effect as of the date that this permit is issued,

**10 CSR 10-6.065(6)(C)1.B Permit Duration**

This permit is issued for a term of five years, commencing on the date of issuance. This permit will expire at the end of this period unless renewed.

**10 CSR 10-6.065(6)(C)1.C General Recordkeeping and Reporting Requirements**

1) Recordkeeping
   a) All required monitoring data and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report or application.
   b) Copies of all current operating and construction permits issued to this installation shall be kept on-site for as long as the permits are in effect. Copies of these permits shall be made immediately available to any Missouri Department of Natural Resources' personnel upon request.
2) Reporting
   a) All reports shall be submitted to the Air Pollution Control Program, Enforcement Section, P. O. Box 176, Jefferson City, MO 65102.
   b) The permittee shall submit a report of all required monitoring by:
      i) October 1st for monitoring which covers the January through June time period, and
      ii) April 1st for monitoring which covers the July through December time period.
      iii) Exception. Monitoring requirements which require reporting more frequently than semi annually shall report no later than 30 days after the end of the calendar quarter in which the measurements were taken.
   c) Each report shall identify any deviations from emission limitations, monitoring, recordkeeping, reporting, or any other requirements of the permit; this includes deviations or Part 64 exceedances.
   d) Submit supplemental reports as required or as needed. Supplemental reports are required no later than ten days after any exceedance of any applicable rule, regulation or other restriction. All reports of deviations shall identify the cause or probable cause of the deviations and any corrective actions or preventative measures taken.
      i) Notice of any deviation resulting from an emergency (or upset) condition as defined in paragraph (6)(C)7.A of 10 CSR 10-6.065 (Emergency Provisions) shall be submitted to the permitting authority either verbally or in writing within two working days after the date on which the emission limitation is exceeded due to the emergency, if the permittee wishes to assert an affirmative defense. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that indicate an emergency occurred and the permittee can identify the cause(s) of the emergency. The permitted installation must show that it was operated properly at the time and that during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or requirements in the permit. The notice must contain a description of the emergency, the steps taken to mitigate emissions, and the corrective actions taken.

ii) Any deviation that poses an imminent and substantial danger to public health, safety or the environment shall be reported as soon as practicable.
iii) Any other deviations identified in the permit as requiring more frequent reporting than the permittee's semiannual report shall be reported on the schedule specified in this permit, and no later than ten days after any exceedance of any applicable rule, regulation, or other restriction.

e) Every report submitted shall be certified by the responsible official, except that, if a report of a deviation must be submitted within ten days after the deviation, the report may be submitted without a certification if the report is resubmitted with an appropriate certification within ten days after that, together with any corrected or supplemental information required concerning the deviation.
f) The permittee may request confidential treatment of information submitted in any report of deviation.

**10 CSR 10-6.065(6)(C)1.D Risk Management Plan Under Section 112(r)**

The permittee shall comply with the requirements of 40 CFR Part 68, Accidental Release Prevention Requirements. If the permittee has more than a threshold quantity of a regulated substance in process, as determined by 40 CFR Section 68.115, the permittee shall submit a Risk Management Plan in accordance with 40 CFR Part 68 no later than the latest of the following dates:

1) June 21, 1999;
2) Three years after the date on which a regulated substance is first listed under 40 CFR Section 68.130; or
3) The date on which a regulated substance is first present above a threshold quantity in a process.

**10 CSR 10-6.065(6)(C)1.F Severability Clause**

In the event of a successful challenge to any part of this permit, all uncontested permit conditions shall continue to be in force. All terms and conditions of this permit remain in effect pending any administrative or judicial challenge to any portion of the permit. If any provision of this permit is invalidated, the permittee shall comply with all other provisions of the permit.

**10 CSR 10-6.065(6)(C)1.G General Requirements**

1) The permittee must comply with all of the terms and conditions of this permit. Any noncompliance with a permit condition constitutes a violation and is grounds for enforcement action, permit termination, permit revocation and re-issuance, permit modification or denial of a permit renewal application.
2) The permittee may not use as a defense in an enforcement action that it would have been necessary for the permittee to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit
3) The permit may be modified, revoked, reopened, reissued or terminated for cause. Except as provided for minor permit modifications, the filing of an application or request for a permit modification, revocation and reissuance, or termination, or the filing of a notification of planned changes or anticipated noncompliance, does not stay any permit condition.
4) This permit does not convey any property rights of any sort, nor grant any exclusive privilege.
5) The permittee shall furnish to the Air Pollution Control Program, upon receipt of a written request and within a reasonable time, any information that the Air Pollution Control Program reasonably may require to determine whether cause exists for modifying, reopening, reissuing or revoking the permit or to determine compliance with the permit. Upon request, the permittee also shall furnish to

the Air Pollution Control Program copies of records required to be kept by the permittee. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 10 CSR 10-6.065(6)(C)1.

**10 CSR 10-6.065(5)(C)1.H Incentive Programs Not Requiring Permit Revisions**

No permit revision will be required for any installation changes made under any approved economic incentive, marketable permit, emissions trading, or other similar programs or processes provided for in this permit.

**10 CSR 10-6.065(5)(C)1.I.C Reasonably Anticipated Operating Scenarios**

None.

**10 CSR 10-6.065(5)(C)1.I.E Title IV Allowances**

This permit shall prohibit emissions which exceed any allowances the installation holds under Title IV of the Clean Air Act.

1) No permit revisions shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program if the increases do not require a permit revision under any other applicable requirement.
2) Limits cannot be placed on the number of allowances that may be held by an installation. The installation may not use these allowances, however, as a defense for noncompliance with any other applicable requirement.
3) Any allowances held by a Title IV installation shall be accounted for according to procedures established in rules promulgated under Title IV of the Clean Air Act.
4) Kansas City Power and Light - Montrose Generating Station was issued a Title IV: Phase II Acid Rain Permit on January 22, 1999, with effective dates from January 1, 2000 through December 31, 2004. The Missouri Department of Natural Resources project number of this permit is 1998-09-049 and its ORIS code is 2080. Kansas City Power and Light – Montrose Generating Station applied for a renewal of this permit on September 4, 2004 which reflected no change in the installation's status.

**10 CSR 10-6.065(6)(C)3 Compliance Requirements**

1) Any document (including reports) required to be submitted under this permit shall contain a certification signed by the responsible official.
2) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized officials of the Missouri Department of Natural Resources, or their authorized agents, to perform the following (subject to the installation's right to seek confidential treatment of information submitted to, or obtained by, the Air Pollution Control Program):
   a) Enter upon the premises where a permitted installation is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this permit;
   b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
   c) Inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
   d) As authorized by the Missouri Air Conservation Law, Chapter 643, RSMo or the Act, sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the terms of this permit, and all applicable requirements as outlined in this permit.

3) All progress reports required under an applicable schedule of compliance shall be submitted semiannually (or more frequently if specified in the applicable requirement). These progress reports shall contain the following:
   a) Dates for achieving the activities, milestones or compliance required in the schedule of compliance, and dates when these activities, milestones or compliance were achieved, and
   b) An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measures adopted.
4) The permittee shall submit an annual certification that it is in compliance with all of the federally enforceable terms and conditions contained in this permit, including emissions limitations, standards, or work practices. These certifications shall be submitted annually by April 1st, unless the applicable requirement specifies more frequent submission. These certifications shall be submitted to EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, as well as the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102. All deviations and Part 64 exceedances and excursions must be included in the compliance certifications. The compliance certification shall include the following:
   a) The identification of each term or condition of the permit that is the basis of the certification;
   b) The current compliance status, as shown by monitoring data and other information reasonably available to the installation;
   c) Whether compliance was continuous or intermittent;
   d) The method(s) used for determining the compliance status of the installation, both currently and over the reporting period; and
   e) Such other facts as the Air Pollution Control Program will require in order to determine the compliance status of this installation.

**10 CSR 10-6.065(6)(C)6 Permit Shield**

1) Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements as of the date that this permit is issued, provided that:
   a) The application requirements are included and specifically identified in this permit, or
   b) The permitting authority, in acting on the permit revision or permit application, determines in writing that other requirements, as specifically identified in the permit, are not applicable to the installation, and this permit expressly includes that determination or a concise summary of it.
2) Be aware that there are exceptions to this permit protection. The permit shield does not affect the following:
   a) The provisions of section 303 of the Act or section 643.090, RSMo concerning emergency orders,
   b) Liability for any violation of an applicable requirement which occurred prior to, or was existing at, the time of permit issuance,
   c) The applicable requirements of the acid rain program,
   d) The authority of the Environmental Protection Agency and the Air Pollution Control Program of the Missouri Department of Natural Resources to obtain information, or
   e) Any other permit or extra-permit provisions, terms or conditions expressly excluded from the permit shield provisions.

**10 CSR 10-6.065(6)(C)7 Emergency Provisions**

1) An emergency or upset as defined in 10 CSR 10-6.065(6)(C)7.A shall constitute an affirmative defense to an enforcement action brought for noncompliance with technology-based emissions

limitations. To establish an emergency- or upset-based defense, the permittee must demonstrate, through properly signed, contemporaneous operating logs or other relevant evidence, the following:
a) That an emergency or upset occurred and that the permittee can identify the source of the emergency or upset,
b) That the installation was being operated properly,
c) That the permittee took all reasonable steps to minimize emissions that exceeded technology-based emissions limitations or requirements in this permit, and
d) That the permittee submitted notice of the emergency to the Air Pollution Control Program within two working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and any corrective actions taken.

2) Be aware that an emergency or upset shall not include noncompliance caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

**10 CSR 10-6.065(6)(C)8 Operational Flexibility**

An installation that has been issued a Part 70 operating permit is not required to apply for or obtain a permit revision in order to make any of the changes to the permitted installation described below if the changes are not Title I modifications, the changes do not cause emissions to exceed emissions allowable under the permit, and the changes do not result in the emission of any air contaminant not previously emitted. The permittee shall notify the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as well as EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, at least seven days in advance of these changes, except as allowed for emergency or upset conditions. Emissions allowable under the permit means a federally enforceable permit term or condition determined at issuance to be required by an applicable requirement that establishes an emissions limit (including a work practice standard) or a federally enforceable emissions cap that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject.

1) Section 502(b)(10) changes. Changes that, under section 502(b)(10) of the Act, contravene an express permit term may be made without a permit revision, except for changes that would violate applicable requirements of the Act or contravene federally enforceable monitoring (including test methods), recordkeeping, reporting or compliance requirements of the permit.
   a) Before making a change under this provision, The permittee shall provide advance written notice to the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as well as EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, describing the changes to be made, the date on which the change will occur, and any changes in emission and any permit terms and conditions that are affected. The permittee shall maintain a copy of the notice with the permit, and the APCP shall place a copy with the permit in the public file. Written notice shall be provided to the EPA and the APCP as above at least seven days before the change is to be made. If less than seven days notice is provided because of a need to respond more quickly to these unanticipated conditions, the permittee shall provide notice to the EPA and the APCP as soon as possible after learning of the need to make the change.
   b) The permit shield shall not apply to these changes.

**10 CSR 10-6.065(6)(C)9 Off-Permit Changes**

1) Except as noted below, the permittee may make any change in its permitted operations, activities or emissions that is not addressed in, constrained by or prohibited by this permit without obtaining a permit revision. Insignificant activities listed in the application, but not otherwise addressed in or

prohibited by this permit, shall not be considered to be constrained by this permit for purposes of the off-permit provisions of this section. Off-permit changes shall be subject to the following requirements and restrictions:

a) The change must meet all applicable requirements of the Act and may not violate any existing permit term or condition; the permittee may not change a permitted installation without a permit revision if this change is subject to any requirements under Title IV of the Act or is a Title I modification;
b) The permittee must provide written notice of the change to the Air Pollution Control Program, Enforcement Section, P.O. Box 176, Jefferson City, MO 65102, as well as EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101, no later than the next annual emissions report. This notice shall not be required for changes that are insignificant activities under 10 CSR 10-6.065(6)(B)3. This written notice shall describe each change, including the date, any change in emissions, pollutants emitted and any applicable requirement that would apply as a result of the change.
c) The permittee shall keep a record describing all changes made at the installation that result in emissions of a regulated air pollutant subject to an applicable requirement and the emissions resulting from these changes; and
d) The permit shield shall not apply to these changes.

**10 CSR 10-6.020(2)(R)12 Responsible Official**

The application utilized in the preparation of this permit was signed by James D. Teaney. On October 1, 2004, the Air Pollution Control Program was informed that Greg Lee, Plant Manager is now the responsible official. If this person terminates employment, or is reassigned different duties such that a different person becomes the responsible person to represent and bind the installation in environmental permitting affairs, the owner or operator of this air contaminant source shall notify the Director of the Air Pollution Control Program of the change. Said notification shall be in writing and shall be submitted within 30 days of the change. The notification shall include the name and title of the new person assigned by the source owner or operator to represent and bind the installation in environmental permitting affairs. All representations, agreement to terms and conditions and covenants made by the former responsible person that were used in the establishment of limiting permit conditions on this permit will continue to be binding on the installation until such time that a revision to this permit is obtained that would change said representations, agreements and covenants.

**10 CSR 10-6.065(6)(E)6 Reopening-Permit for Cause**

This permit may be reopened for cause if:

1) The Missouri Department of Natural Resources (MDNR) receives notice from the Environmental Protection Agency (EPA) that a petition for disapproval of a permit pursuant to 40 CFR §70.8(d) has been granted, provided that the reopening may be stayed pending judicial review of that determination,
2) MDNR or EPA determines that the permit contains a material mistake or that inaccurate statements were made which resulted in establishing the emissions limitation standards or other terms of the permit,
3) Additional applicable requirements under the Act become applicable to the installation; however, reopening on this ground is not required if—:
   a) The permit has a remaining term of less than three years;
   b) The effective date of the requirement is later than the date on which the permit is due to expire; or

c) The additional applicable requirements are implemented in a general permit that is applicable to the installation and the installation receives authorization for coverage under that general permit,

4) The installation is an affected source under the acid rain program and additional requirements (including excess emissions requirements), become applicable to that source, provided that, upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into the permit; or

5) MDNR or EPA determines that the permit must be reopened and revised to assure compliance with applicable requirements.

**10 CSR 10-6.065(6)(E)1.C Statement of Basis**

This permit is accompanied by a statement setting forth the legal and factual basis for the draft permit conditions (including references to applicable statutory or regulatory provisions). This Statement of Basis, while referenced by the permit, is not an actual part of the permit.

# VI. Attachments

Attachments follow.

## ATTACHMENT A
## Production and Emissions Record

This recordkeeping sheet or an equivalent form may be used for the recordkeeping requirements of Permit Condition (EU0010 and EU0020)-001.

| Month/ Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 12 Month Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal Received (tons) | | | | | | | | | | | | | |
| *Emissions (tons) | | | | | | | | | | | | | |

*Emissions = (coal received in tons) X 0.00352 lb/ton ÷ 2,000 lb/ton. The 12-month total emissions must equal 14.9 tons, or less, to maintain compliance.

## ATTACHMENT B
## Method 22 (Outdoor) Observation Log

This recordkeeping sheet or an equivalent form may be used for the recordkeeping requirements of 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants.*

| Method 22 Opacity Emission Observations | | | | |
|---|---|---|---|---|
| Date | Method 22 Test Observer | Visible Emissions? (yes/no) | Typical Emissions? (yes/no) | If visible and not typical was a Method 9 done? (yes/no) |
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## ATTACHMENT C
## Inspection/Maintenance/Repair/Malfunction Log

This recordkeeping sheet or an equivalent form may be used to record inspections of equipment, maintenance repairs and malfunctions.

| Inspection/Maintenance/Repair/Malfunction Log | | |
|---|---|---|
| Date | Emission Unit/Equipment | Activities Performed |
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## ATTACHMENT D
## Method 9 Opacity Emissions Observations

This recordkeeping sheet or an equivalent form may be used for the recordkeeping requirements of 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants*.

| Method 9 Opacity Emissions Observations | |
|---|---|
| Company | Observer |
| Location | Observer Certification Date |
| Date | Emission Unit |
| Time | Control Device |

| Hour | Minute | Seconds | | | | Steam Plume (check if applicable) | | Comments |
|---|---|---|---|---|---|---|---|---|
| | | 0 | 15 | 30 | 45 | Attached | Detached | |
| | 0 | | | | | | | |
| | 1 | | | | | | | |
| | 2 | | | | | | | |
| | 3 | | | | | | | |
| | 4 | | | | | | | |
| | 5 | | | | | | | |
| | 6 | | | | | | | |
| | 7 | | | | | | | |
| | 8 | | | | | | | |
| | 9 | | | | | | | |
| | 10 | | | | | | | |
| | 11 | | | | | | | |
| | 12 | | | | | | | |
| | 13 | | | | | | | |
| | 14 | | | | | | | |
| | 15 | | | | | | | |
| | 16 | | | | | | | |
| | 17 | | | | | | | |
| | 18 | | | | | | | |

| SUMMARY OF AVERAGE OPACITY | | | | |
|---|---|---|---|---|
| Set Number | Time | | Opacity | |
| | Start | End | Sum | Average |
| | | | | |
| | | | | |
| | | | | |

Readings ranged from _____ to _____ % opacity.

Was the emission unit in compliance at the time of evaluation? _____ _____ _____
YES NO Signature of Observer

## ATTACHMENT E
## 10 CSR 10-6.260 Compliance Demonstration

This attachment may be used to demonstrate that EU0080 Emergency Fire Pump Engine and EU0090 Emergency Generator are always in compliance with 10 CSR 10-6.260, *Restriction of Emission of Sulfur Compounds*

General Equation

ppmv $SO_2$ = $SO_2$ Emission Factor in lb/MMBtu X F Factor in MMBtu/wscf X Conversion Factor for lb/scf to ppm X Conversion Factor for ppmw to ppmv

1) $SO_2$ emission factor for diesel engines < 600 HP = 0.29 lb/MMBtu (From AP-42 Table 3.3-1)

2) The F factor is the ratio of gas volume of products of combustion to the heat content of the fuel. For fuel oil the F factor = 1 MMBtu / 10,320 wscf (From Part 60 Appendix A Method 19 Table 19-2)

3) Conversion factor for lb/scf to ppm = ppm / 1.660E-7 lb/scf (From Part 60 Appendix A Method 19 Table 19-1)

4) Conversion factor for ppmw to ppmv = (28.8 / Molecular Weight of $SO_2$) ppmv / 1 ppmw = (28.8/64) ppmv / ppmw= 0.45 ppmv / ppmw (From AP-42 Appendix A)

Compliance Demonstration

$$ppmv\ SO_2 = \left(0.29\ lb/MMBtu\right)\left(MMBtu/10{,}320\ ft^3\right)\left(ppmw/1.667E^{-7}\ lb/scf\right)\left(0.45\ ppmv/ppmw\right) = 76\ ppmv$$

76 ppmv $SO_2$ << 500 ppmv $SO_2$, so EU0080 and EU0090 are always in compliance

# STATEMENT OF BASIS

**Permit Reference Documents**
These documents were relied upon in the preparation of the operating permit. Because they are not incorporated by reference, they are not an official part of the operating permit.

1) Part 70 Renewal Operating Permit Application, received 06/23/04;
2) 2004 Emissions Inventory Questionnaire, received 03/31/05;
3) U.S. EPA document AP-42, *Compilation of Air Pollutant Emission Factors*; Volume I, Stationary Point and Area Sources, Fifth Edition (AP-42.)

**History and Notes on Emission Units Without Limitations**

1) Bottom unloading from railcar (EP-01) has been removed from the installation.

2) Coal storage piles (EP-02), fly ash unloading to open storage pile (EP-12), and fly ash pile maintenance activities (EP-13) are fugitive sources, which do not emit regulated pollutants from a discrete stack or vent. They emit particulate matter directly into the ambient air, and do not have any type of capture/control devices. They are not subject to any specific rule except the installation wide requirement of 10 CSR 10-6.170, *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin.* (See items 2 and 4 in Other Regulatory Determinations below.)

3) Coal crusher (EP-04) is not subject to any specific rule. (See item 5 in NSPS Applicability and items 2 and 4 in Other Regulatory Determinations below.) In any case, it is inoperable. The coal is still conveyed through the coal crusher house, but is not crushed.

4) One 1,000,000-gallon fuel oil storage tank installed pre 1970's (EP-05), two 40,000-gallon fuel oil storage tanks installed pre 1970's, one 10,000-gallon used oil tank, one 2,000-gallon split fuel oil/gasoline storage tank, one 400-gallon diesel tank, one 300-gallon diesel tank, one 250-gallon gasoline tank, and two 240-gallon gasoline tanks are not subject to any specific rule. (See NSPS Applicability below.)

5) Haul roads are fugitive sources, which do not emit regulated pollutants from a discrete stack or vent. They emit particulate matter directly into the ambient air, and do not have any type of capture/control devices. They are not subject to any specific rule except the installation wide requirement of 10 CSR 10-6.170, *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin.* (See item 4 in Other Regulatory Determinations below.)

6) Painting, maintenance (EP-208), sand blasting, maintenance (EP-210) and portable pump, maintenance (EP-206) are plant maintenance and upkeep activities or repair or maintenance shop activities which are not conducted as part of the installation's primary business activity. They are activities not required to be listed in the operating permit application. Painting is done occasionally in a small shed, not a typical paint booth with filters, and has only fugitive emissions. Sand blasting is done with a small unit – the size of a rabbit cage – and has only minor emissions. The portable pump is used occasionally to clean up flooding.

7) Solvent parts cleaner/degreaser (EP-43, EP-61, and EP-205), backup engine for Tainter gate (0.5 MMBtu/hr) (EP-64), fly ash silo vents (EP-94, EP-95, EP-96, EP-105, and two others), and portable heating units (EP-207) qualify as insignificant activities.

**Applicable Requirements Included in the Operating Permit but Not in the Application or Previous Operating Permits**

In the operating permit application, the installation indicated they were not subject to the following regulation(s). However, in the review of the application, the agency has determined that the installation is subject to the following regulation(s) for the reasons stated.

None.

**Other Air Regulations Determined Not to Apply to the Operating Permit**

The Air Pollution Control Program (APCP) has determined the following requirements are not applicable to this installation at this time for the reasons stated.

1) 10 CSR 10-3.050, *Restriction of Particulate Matter from Industrial Processes*
   This rule was listed as applicable on the permit application. However, this rule was rescinded on March 20, 2001 and replaced by 10 CSR 10-6.400.

2) 10 CSR 10-3.080, *Restriction of Emission of Visible Air Contaminants*
   This rule was listed as applicable on the permit application. However, this rule was rescinded on May 30, 2000 and replaced by 10 CSR 10-6.220.

3) 10 CSR 10-6.080, *Emission Standards for Hazardous Air Pollutants*
   40 CFR Part 61 Subpart E, *National Emission Standard for Mercury*
   This rule was listed as applicable on the permit application, but is not applicable. See the paragraphs on NESHAP Applicability below.

4) 10 CSR 10-6.100, *Alternate Emission Limits*
   This rule is not applicable because the installation is in an ozone attainment area.

**Construction Permit Revisions**

The following revisions were made to construction permits for this installation.

1) Construction Permit 0296-004 authorized the construction of EU0010 Rotary Coal Car Dumper and EU0020 Rotary Coal Car Dumper Conveyor.
   a) This permit indicated that 10 CSR 10-3.050, *Restriction of Emission of Particulate Matter From Industrial Processes*, was an applicable requirement. This rule was rescinded on March 30, 2001, and was replaced by 10 CSR 10-6.400, *Restriction of Emission of Particulate Matter From Industrial Processes*. This new regulation is not applicable because §(1)(B)(12) specifies that it does not apply to the conveying operations at a power plant.
   b) This permit indicated that 10 CSR 10-3.080, *Restriction of Emission of Visible Air Contaminants*, was an applicable requirement. This rule was rescinded on May 30, 2000, and was replaced b 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants*.
   c) This permit indicated that 10 CSR 10-3.150, *Restriction of Emissions of Sulfur Compounds*, was an applicable requirement. This rule was rescinded on July 30, 1997 and was replaced by 10

CSR 10-6.260, *Restriction of Emission of Sulfur Compounds*. Neither the old nor the new regulation is applicable anyway. The only significant emission from coal unloading, storage, crushing, or screening is particulate matter, not sulfur. (See 11.9 *Western Surface Coal Mining* and 11.10 *Coal Cleaning* in AP-42.)

2) Construction Permit 0699-008 authorized the construction of EU0080 Emergency Generator.
   a) This permit indicated that 10 CSR 10-3.080, *Restriction of Emission of Visible Air Contaminants*, was an applicable requirement. This rule was rescinded on May 30, 2000, and was replaced by 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants*. This new regulation is not applicable because §(1)(A) specifies that it does not apply to internal combustion engines.

**NSPS Applicability**

1) 40 CFR Part 60 Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*
   40 CFR Part 60 Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*
   40 CFR Part 60 Subpart Db, *Standards of Performance for Industrial, Commercial, Institutional Steam Generating Units for Which Construction is Commenced After June 19, 1984*
   These regulations do not apply to this installation's boilers, because they were constructed in 1958, prior to the subparts' applicability dates.

2) 40 CFR Part 60 Subpart Dc, *Standards of Performance for Small Industrial, Commercial, Institutional Steam Generating Units*
   This regulation does not apply to this installation's boilers, because they each have a maximum design heat input capacity greater than 100 MMBtu/hr.

3) 40 CFR Part 60 Subpart K, *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978*
   40 CFR Part 60 Subpart Ka, *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984*
   These regulations apply to storage vessels with capacities greater than 40,000 gallons that are used to store petroleum liquids and were constructed, reconstructed, or modified after certain applicability dates. These regulations do not apply to the 1,000,000-gallon fuel oil storage tank (EP-05) or to the two 40,000,000-gallon fuel oil storage tanks, because they were installed prior to the subparts' applicability dates. These regulations do not apply to the other petroleum liquid storage tanks, because they do not have capacities that greater than 40,000 gallons.

4) 40 CFR Part 60 Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*
   This regulation applies to storage vessels with capacities greater than or equal to 75 $m^3$ (about 19,800 gallons) that are used to store volatile organic liquids and were constructed after July 23,

1984. This regulation does not apply to the 1,000,000-gallon fuel oil storage tank (EP-05) or to the two 40,000-gallon fuel oil storage tanks, because they were installed prior to the subpart's applicability date. This regulation does not apply to the other petroleum liquid storage tanks, because they do not have capacities of at least 75 $m^3$.

5) 40 CFR Part 60 Subpart Y, *Standards of Performance for Coal Preparation Plants*
This regulation applies to thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems constructed after October 24, 1974 at a coal preparation plant.
   a) The definition of "coal processing and conveying equipment" in this regulation is "machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery." EU0010 Rotary Coal Car Dumper and EU0020 Rotary Coal Car Dumper Conveyor do not meet this definition, because the coal goes only to coal storage piles. Therefore this regulation does not apply to them.
   b) EU0030 Coal Transfer and Conveying and the coal crusher (EP-04) were constructed prior to October 24, 1974, the subpart's applicability date. Therefore this regulation does not apply to them. Furthermore, the coal crusher is now inoperable.

None of the other New Source Performance Standards (NSPS) apply to this installation.

**MACT Applicability**

1) 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
This regulation does not apply to EU0080, Emergency Fire Pump Engine or to EU0090, Emergency Generator, because they have ratings of less than 500 brake horsepower.

2) 40 CFR Part 63 Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters*
This subpart does not apply to the EU0050 through EU0070 Boilers, because they are fossil fuel-fired combustion units of more than 25 megawatts that serve as generators that produce electricity for sale.

3) 40 CFR Part 63 Subpart UUUUU, *National Emission Standards for Coal- and Oil- Fired Electric Utility Steam Generating Units*
Coal- and oil- fired electric utility steam generating units were removed from the section 112(c) list of regulated source categories on March 29, 2005.

None of the other Maximum Available Control Technology (MACT) regulations apply to this installation.

**NESHAP Applicability**

1) 10 CSR 10-6.080, *Emission Standards for Hazardous Air Pollutants*
40 CFR Part 61 Subpart E, *National Emission Standard for Mercury*

This rule is applicable to those stationary sources which process mercury ore to recover mercury, use mercury chlor-alkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge. This installation does none of these things, so this rule is not applicable to it.

2) 10 CSR 10-6.080, *Emission Standards for Hazardous Air Pollutants*
40 CFR Part 61 Subpart M, *National Emission Standard for Asbestos*
10 CSR 10-6.250, *Asbestos Abatement Projects – Certification, Accreditation, and Business Exemption Requirements*
Missouri Air Conservation Law, 643.225 through 643.250, *Asbestos Abatement*
In the permit application and according to APCP records, there was no indication that any of these regulations apply to this installation. The installation is subject to these regulations if they undertake any projects that deal with or involve any asbestos containing materials. None of the installation's operating projects underway at the time of this review deal with or involve asbestos containing material. Therefore, the above regulations were not cited in the operating permit. If the installation should undertake any construction or demolition projects in the future that deal with or involve any asbestos containing materials, the installation must follow all of the applicable requirements of the above rules related to that specific project.

None of the other National Emission Standards for Hazardous Air Pollutants (NESHAP) apply to this installation.

**CAM Applicability**
EU0050 through EU0070 Boilers meet the applicability criteria for 40 CFR Part 64, *Compliance Assurance Monitoring (CAM)*, because these units each have the uncontrolled potential to emit particulate matter above the major source threshold levels (as defined by Part 70) and utilize control devices (as defined by 40 CFR §64.1) to comply with 10 CSR 10-3.060.

The permittee submitted a Compliance Assurance Monitoring plan with the renewal permit application, and then submitted a replacement CAM plan on February 25, 2005. The replacement CAM plan was approved by the Missouri Department of Natural Resources, Air Pollution Control Program, Compliance/Enforcement Section. A copy of the relevant memos and the approved CAM plan are attached at the end of this Statement of Basis .

The permittee also submitted a CAM test plan schedule on May 22, 2006, and a CAM test plan on July 24, 2006. Both of these were approved by the Missouri Department of Natural Resources, Air Pollution Control Program, Compliance/Enforcement Section. Copies of these are also attached at the end of this Statement of Basis.

This accepted Compliance Assurance Monitoring has been incorporated into Permit Condition (EU0050-through EU0070)-001.

Where conflicts arise between 40 CFR Part 60 and the approved CAM plan and CAM test plan, the CAM plan and CAM test plan govern. This will assure that where there is doubt, the acceptance criteria in the CAM plan and CAM test plan will be used, and not those in 40 CFR Part 60 Appendix B Performance Specification 11 (PS-11). These monitors are indicators of compliance, and not compliance monitors. The full PS-11 requirements do not apply to monitors that are only indicators of compliance.

**Other Regulatory Determinations**

1) 10 CSR 10-6.220, *Restriction of Emission of Visible Air Contaminants*
Per §(1)(A), this regulation does not apply to the following emission units, because they are internal combustion engines.
   a) EU0080 Emergency Fire Pump Engine
   b) EU0090 Emergency Generator

2) 10 CSR 10-6.260, *Restriction of Emissions of Sulfur Compounds*
This regulation does not apply to the following emission units, because the only significant emission from coal unloading, storage, crushing, or screening is particulate matter. (See 11.9 Western Surface Coal Mining and 11.10 Coal Cleaning in AP-42.)
   a) EU0010 Rotary Coal Dumper
   b) EU0020 Rotary Coal Dumper Conveyor
   c) EU0030 Coal Transfer and Conveying
   d) Coal storage piles
   e) Coal crusher (inoperable)

   This regulation does not apply to the following emission units, because the only significant emission from fly ash handling is particulate matter. (See 1.1 and 1.2 Coal Combustion in AP-42.)
   f) EU0040 Fly Ash Unloading to Trucks
   g) Fly ash unloading to open storage piles (EP-12)
   h) Fly ash pile maintenance activities (EP-13)

   Note: In the 8/31/05 revision to 10 CSR 10-6.260, Missouri DNR decreased Kansas City Power & Light - Montrose Station's $SO_2$ emission rate limit from 12.9 lb/MMBtu to 1.3 lb/MMBtu and increased the averaging time from a three hour average to an annual average. These revisions to the Missouri's SIP were disapproved by the EPA on October 3, 2005. Therefore, the underlying state regulation prior to the state's revision remains as the federally enforceable requirement.

3) 10 CSR 10-6.360, *Control of $NO_X$ Emissions From Electric Generating Units and Non- Electric Generating Boilers*
This regulation is not applicable in Henry County.

4) 10 CSR 10-6.400, *Restriction of Emissions of Particulate Matter From Industrial Processes*
Per §(1)(B)(12), this regulation does not apply to the following emission units, because they are part of the grinding, crushing, and conveying operations at a power plant.
   a) EU0010 Rotary Coal Dumper
   b) EU0020 Rotary Coal Dumper Conveyor
   c) EU0030 Coal Transfer and Conveying
   d) Coal crusher (EP-04

   Per §(1)(B)(6), this regulation does not apply to the following emission unit, because it burns fuel for indirect heating.
   e) EU0050 through EU0070 Boilers

   The only materials introduced into the following emission units which may cause an emission of particulate matter are their fuels. Per §(2)(A), liquids and gases used solely as fuels and air

introduced for the purposes of combustion are excluded from consideration. Therefore the process weight rate for these emission units is zero, and the regulation does not apply.

f) EU0080 Emergency Fire Pump Engine
g) EU0090 Emergency Generator

Per §(1)(B)(7), this regulation does not apply to the following emission units, because they have only fugitive emissions.

h) Coal storage piles (EP-02)
i) EU0040 Fly Ash Unloading to Trucks
j) Fly ash unloading to open storage piles (EP-12)
k) Fly ash pile maintenance activities (EP-13)
l) Haul roads (EP-14)

5) September 30, 1988 MDNR letter re: *Emissions banked from use by Kansas City Power & Light Under 10 CSR 10-6.060*, signed by Randy Raymond.
This letter established an annual $SO_2$ emission rate of 1.3 pound per million BTU heat input (1.3 lb/MMBtu) which is included in Permit Condition (EU0050 through EU0070)-003 . In addition, the letter contained recordkeeping and reporting requirements. These requirements are redundant to those recordkeeping and reporting requirements contained in 40 CFR Part 75 and are therefore not listed separately in Permit Condition (EU0050 through EU0070)-003.

**Other Regulations Not Cited in the Operating Permit or the Above Statement of Basis**

Any regulation which is not specifically listed in either the Operating Permit or in the above Statement of Basis does not appear, based on this review, to be an applicable requirement for this installation for one or more of the following reasons:

1) The specific pollutant regulated by that rule is not emitted by the installation.
2) The installation is not in the source category regulated by that rule.
3) The installation is not in the county or specific area that is regulated under the authority of that rule.
4) The installation does not contain the type of emission unit which is regulated by that rule.
5) The rule is only for administrative purposes.

Should a later determination conclude that the installation is subject to one or more of the regulations cited in this Statement of Basis or other regulations which were not cited, the installation shall determine and demonstrate, to the APCP's satisfaction, the installation's compliance with that regulation(s). If the installation is not in compliance with a regulation which was not previously cited, the installation shall submit to the APCP a schedule for achieving compliance for that regulation(s).

**Copies of Information on Compliance Assurance Monitoring (CAM)**

The remaining pages of this Statement of Basis contain the following CAM-related information:

1) The one-page cover memo dated February 25, 2005, from Dan Haas to Compliance/Enforcement Section Chief Steven Feeler for the CAM plans for Iatan generating station and Montrose generating station [SB-9];
2) The eight-page CAM plan for Kansas City Power & Light's Montrose generating station. This is not the version of the CAM plan submitted with the memo in 1) above and included in the draft of this permit which was put on public notice. It is the revised version submitted with comments on February 3, 2006, during the public comment period. It differs from the earlier version in that it uses a Teledyne PM monitor instead of an ESC monitor, and in that it allows for the possibility of putting the monitors in either stacks or ducts [sB-10 through SB=17].

3) The one-page e-mail dated May 22, 2006, from Dan Haas in the Environmental Service Department of Kansas City Power & Light to Ken Volmert in the Compliance/Enforcement Section containing the CAM plan test schedule [SB-18]; and
4) The twenty-five-page CAM Test Plan (Quality Assurance & Quality Control) for Kansas City Power & Light's Montrose generating station, attached to an e-mail dated July 24, 2006, from Dan Haas in the Environmental Service Department of Kansas City Power & Light to Cheryl Steffan in the Permits Section and Ken Volmert in the Compliance/Enforcement Section [SB-19 through SB-43].

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AIR POLLUTION CONTROL PGM

# Kansas City Power & Light®

February 25, 2005

Mr. Steven Feeler
Compliance/Enforcement Section Chief
Missouri Department of Natural Resources
Air Pollution Control Program
P. O. Box 176
Jefferson City, MO 65102-0176

**Re: Compliance Assurance Monitoring Plans for Iatan Generating Station and Montrose Generating Station**

Dear Mr. Feeler:

I am enclosing copies of the proposed Compliance Assurance Monitoring plans for Iatan and Montrose Generating Stations. These CAM plans are intended to replace the ones submitted with the original permit renewal applications submitted earlier.

The plans enclosed are based on the use of a continuous particulate monitor as an indicator of the electrostatic precipitators performance. The plans envision the use of Environmental Services Corporation's Model P-5B monitors, however, KCP&L reserves the right to replace this model with a comparable model if there are problems obtaining this particular model. Pursuant to 40 CFR 64.6 (d) a proposed schedule for the installation and testing of these plans should be included as part of the operating permits when issued, and it is KCP&L's understanding that the installation and testing should be completed within 180 days of permit issuance pursuant to 40 CFR 64.4 (e).

Please feel free to contact me directly with any comments or concerns. My phone number is 816-556-2998.

Sincerely,

Dan Haas

Dan Haas
Environmental Service Department

Enclosures (2)
cc: K. Volmert (MoDNR)
T. Eaton (KCP&L - Environmental Services)
G. Brown (Iatan)
D. Kelsay (Montrose)
P. May (Environmental Services)

**COMPLIANCE ASSURANCE MONITORING PLAN**
**Kansas City Power & Light Company's - Montrose Station**

**Background**

Emission Unit:

Description: Unit 1 - Combusion Engineering Tangential-Fired Boiler, 1668 MMBtu/Hr.
Unit 2 - Combusion Engineering Tangential-Fired Boiler, 1668 MMBtu/Hr.
Unit 3 - Combusion Engineering Tangential-Fired Boiler, 1640 MMBtu/Hr.
(Unit 2 and 3 exhaust through a commom stack)

Facility: Montrose Generating Station
400 SW Highway P
Clinton, Missouri 64735

Applicable Requirement:

Regulation: 10 CSR 10-3.060, Maximum Allowable Emission of Particulate Matter From Fuel Burning Equipment Used for Indirect Heating

Pollutants: Particulate Matter (PM)

Emission Limit: 0.20 Lb PM per MMBtu on a station-wide average basis, except during periods of startup, shutdown and malfunction per 40 CFR 60.8(c).

Monitoring Requirements: Per Regulations - None.
Per Operating Permit - Current gap-filing compliance demonstration is the monitoring of four parameters indicating electrostatic precipitators performance.

Per Proposed CAM: A Teledyne Monitor Labs Model 360 Laserhawk particulate monitor installed in stacks or ducts to serve as an indicator of precipitator performance.

Control Technology: Three Cold-side Research Cottrell Electrostatic Precipitators (ESP), one per unit.

**COMPLIANCE ASSURANCE MONITORING PLAN**
**Kansas City Power & Light Company's - Montrose Station**

**Monitoring Approach**

The key elements of the monitoring approach are presented in Table 1. The CAM performance indicators are continuous Particulate Monitors, Model 360 (CEMs), manufactured by Teledyne Monitor Labs (TML), Englewood, Colorado. The Monitors output will be used to provide a reasonable level of compliance assurance by indicating ESP performance. The CEMs readings shall not be used to directly demonstrate compliance with 10 CSR 10-3.060 limits.

TABLE 1. MONITORING APPROACH

| | |
|---|---|
| I. Indicator | Particulate Level of each stack (2 each) or duct (3 each) exhaust, as measured by the output of a continuous PM monitor, TML Model 360. The monitor's output will be recorded in units of pounds PM per cubic feet or pounds PM per megawatt. Correlation between the monitors output and Reference Method will be established during performance tests. |
| Measurement Approach | PM CEMs in each stack or duct. An Excursion will occur when the hourly PM CEMs reading reaches or exceeds a value equivalent to 1.25 times the highest PM CEMs response value reached during the correlation tests, or 0.9 times the source emissions limit. Corrective action must be taken at this time to bring the unit back within these limits (see section on Inspection/Corrective Action) |
| II. Indicator Range | The PM monitor indicator range is an hourly average reading covering the full range of measurements made during the initial calibration plus 25%. The indicator range is a calibrated instrument output that offers reasonable assurance of compliance with the PM emissions limit. An Excursion (defined above and in section on Inspection/Corrective Action) triggers corrective action. |
| III. Performance Criteria<br>A. Representativeness | The PM CEMs are installed at locations in each stack or duct chosen to minimize problems due to flow disturbances or varying PM stratification. Prior to installation, measurements shall be made of flow dynamics and/or particulate matter to determine the existence or extent of PM stratification. |
| B. Verification of Operational Status | Initial correlation tests will be conducted as specified in this document, with a minimum of 9 valid test runs at three different PM concentration levels per stack or duct. The results of these tests will be used to determine the correlation equation and correlation coefficient for each stack or duct. See section on instrument calibration for definition of "valid" test run. |
| C. QA/QC Practices and Criteria | Daily Zero and Span checks will be made, and the results documented. The instruments will be recalibrated if the Zero or Span values exceed plus or minus 5% of the reference value. In addition, quarterly reference calibrations, routine and recommended periodic maintenance procedures will be performed in accordance with the Manufacturer's instructions. |

| | |
|---|---|
| D. Monitoring Frequency | The PM concentration of the stacks is monitored continuously. |
| E. Data Collection Procedures | The DAHS retains all hourly average PM concentration data, plus all daily Zero-Span calibrations. Alarms will signal an instrument malfunction or excursion. |
| F. Averaging Period | One minute average PM concentration data are used to calculate hourly block averages. |

**Monitoring Approach Justification**

Background:

The pollutant specific emission units are three tangentially-fired steam electric boilers. Unit 1 routes exhaust to a dedicated stack, while Units 2 and 3 route exhaust to a common stack. Units 1 and 2 are rated at 1668 MMBtu/hour, while Unit 3 is rated at 1640 MMBtu/hour. Each boiler has a dedicated ESP, which controls particulate emissions. All three units were constructed before April 3, 1971, and are therefore considered "existing" per 10 CSR 10-3.060. First choice for location of the TML Laserhawk Model 360 PM monitor will be the duct leading to the stack with the alternate location the stack itself. The installation location will be determined by stratification testing.

Rationale for Selection of Performance Indicator

The CAM indicator selected is an "In-Situ" Particulate Monitor CEMs based on light scattering principles, Model 360 Laserhawk, manufactured by Teledyne Monitor Labs, Englewood, CO. The rational for the choice of this specific approach is as follows:

Continuous PM monitors are widely used to measure and report PM emissions in many parts of the world and considered to be reliable real-time indicators of actual mass concentrations.

Rather than using a COMs as a precursor to further action (i.e. calculation of PM emissions via ESP model evaluation) the continuous PM monitor output can directly trigger the need for corrective action and/or reporting obligations.

The TML instrument has been designed and developed leveraging off prior backscattering technologies of its Model 300L backscatter device and its Model 500C, 550 and 560 COMs. All models have hundreds of applications throughout the world and TML is the number one supplier of compliance opacity monitors in the world with over 3,500 installations.

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The TML instrument has an excellent record for reliability and low maintenance and is widely known within every EPA region and within each state.

The TML Model 360 is an extension of its Model 300L which was installed in over 100 applications. The new Model 360 has been field-tested and has met PS-11 and Appendix F Procedure 2 specifications.

The TML instrument is or can be compatible with existing DAHS system, which can readily be set up to record the appropriate averages, calibrations and signal for instrument malfunction or PM exceedences. The I/O interface can use analogs, digital inputs, dry contacts, 232, 422, or 485 interface capabilities. Ethernet capability will be available in the near future.

Instrument Calibration

a. General and Pre-Test Monitoring Period. The instruments will be calibrated based on the boiler load, coal, and ESP characteristics and any other performance or test data deemed applicable. Reference method measurements will be conducted in accordance with accepted method standards (normally EPA Methods 5 or 17) and compared with the integrated (arithmetic average) PM CEMs output over the reference method test period as described below.

   The Model 360 will be installed at a vertical stack location in each stack or horizontal in the duct as recommended by KCP&L. From a practical perspective, this would be a location with existing plat-forming, access and power. The monitors will be initially operated for a period of approximately 30 days under various operating conditions to identify conditions necessary to produce three target concentration levels for the correlation testing (see below). During the 30-day pre-test monitoring period the following key operating parameters will be recorded on each stack:

   Monitor Output
   Plant Load
   ESP Voltage and Current Readings

b. Correlation/Performance Testing. A minimum of nine valid runs (e.g. 3 PM concentration loads and 3 tests per condition) will be used to obtain the correlation equation and correlation coefficient on each stack or within each duct. A run will be declared "not valid" only when performed during a time when conditions are clearly not representative of normal operations, including periods of startup, shutdown and malfunction. The correlation coefficient will be calculated according to equation 11-3 of PS-11, and the correlation

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coefficient will be calculated according to equation 11-14 of the referenced document.

c. Tests should be performed at three different PM concentration levels, with a minimum of three tests at each level, if possible. Level 1 encompasses the range from 0 to 50% of the maximum PM concentration available. Level 2 should range from 50% to 75% of the maximum concentration, and Level 3 75% to 100% of the maximum concentration. The source should be operated over the complete range of expected conditions, so as to assure that the data produced is representative. The data gathered during the 30-day pre-test monitoring period shall be used to produce the desired concentrations for the test runs on each stack or within each duct. The Montrose Generating Station operates on 100% sub-bituminous, Powder River Basin coal, except during startup, so the fuel should not be a major variable in the correlation testing.

d. During correlation testing, the reference method data and PM CEMs measurements will be converted into units of pounds PM per MMBtu to establish limits comparable to the regulatory standard (0.20 lbs/MMBtu). Once established, these limits will be converted into units of pounds PM per actual stack gas volume, or pounds of PM per megawatt. During operation after testing, the CEMs output, and determination of PM levels with respect to limits, will be conducted only in units of pounds per actual stack gas volume or pounds PM per megawatt.

e. The correlation coefficient (r) for each stack or duct, resulting from the calibration testing must be greater than or equal to 0.75.

f. Once the correlation equation has been determined for each stack or duct, it will be applied to PM CEMs data collected by the Data Recorder.

g. Based on the results of the reference method measurements, the data will be documented in a manner similar to the example shown in Table 2, and plotted as shown in Figure 1. The point at which an alarm occurs, as well as a reporting requirement and corrective action, will be determined when the hourly average of the PM CEMs output reaches the lower of the following limits:

- A value equivalent to 1.25 times the highest PM CEMs response value reached during the correlation tests.
- A value equivalent to 0.9 times the source emission limit.

Inspection/Corrective Action

In the event of an excursion (1-hour CEMs reading indicative of 1.25 times the highest PM CEMs response value reached during correlation tests, or 0.9 times

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the source emissions limit) KCP&L will take steps to identify and correct any operational conditions that may be contributing to the excursion. The operational checks will be made as soon as practicable and may include:

- ESP field checks (T/R voltage, current, spark rate)
- Visual inspection of control equipment
- Unusual fuel characteristics
- Boiler upset conditions

QA/QC Criteria

Factory supplied filter standards will be used to calibrate the instruments at a reference zero and upscale span value. These calibration standards will be maintained in accordance with manufacturer's recommendations. Following this calibration an internal "zero-span" cycle will be initiated, thus establishing initial values for future reference. Daily "zero-span" cycles will follow with the results stored in the data system and compared with the initial values. Should either the "zero or span" value error exceed plus or minus 5% of the starting value, an alarm will be initiated to signal the need for recalibration of the instrument to the factory standards. In addition, a quarterly reference calibration will be performed as described in the instrument operations manual. The factory standards will be used to measure instrument response at a zero and upscale value. Should either of these readings exceed the factory standard by more than plus or minus 5% of the full-scale measurement range the instrument will be reset to the factory standard values. Finally, routine scheduled maintenance procedures will be established in accordance with manufacturer's recommendations.

Data Acquisition Needs

The data system will be set up to perform the following tasks:

- Record the analog output of the PM CEMs.
- Calculate emissions values, in the units of the required standard, and according to the correlation(s) established during the PM CEMs calibration.
- Store the hourly averages of the calculated emissions values.
- Record the daily "zero-span" calibration results.
- Initiate an alarm if any daily zero or span value exceeds the error limit of plus or minus 5%
- Initiate an alarm if the hourly averaged PM CEMs emission value reaches or exceeds the limit value as defined earlier.
- Initiate an alarm on the occurrence of a malfunction status indicator from the Model 360 Laserhawk.

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## REFERENCES

1. *Notice of Data Availability and Request for Comments*, FRL-5941-4, Federal Register, Vol. 2, No. 249 (December 20, 1997).
2. *Results of Continuous PM Monitor Testing at Pleasant Prairie Power Plant*, Ralph L. Roberson, Jon Konings and Charles E. Dene, EPRI CEMs Users Group Meeting, May 16-18, 2001, Charlotte, NC.
3. 40 CFR 60, Appendix B, Performance Specification 11 - Specification and Test Procedure for Particulate Matter Continuous Monitoring Systems at Stationary Sources.

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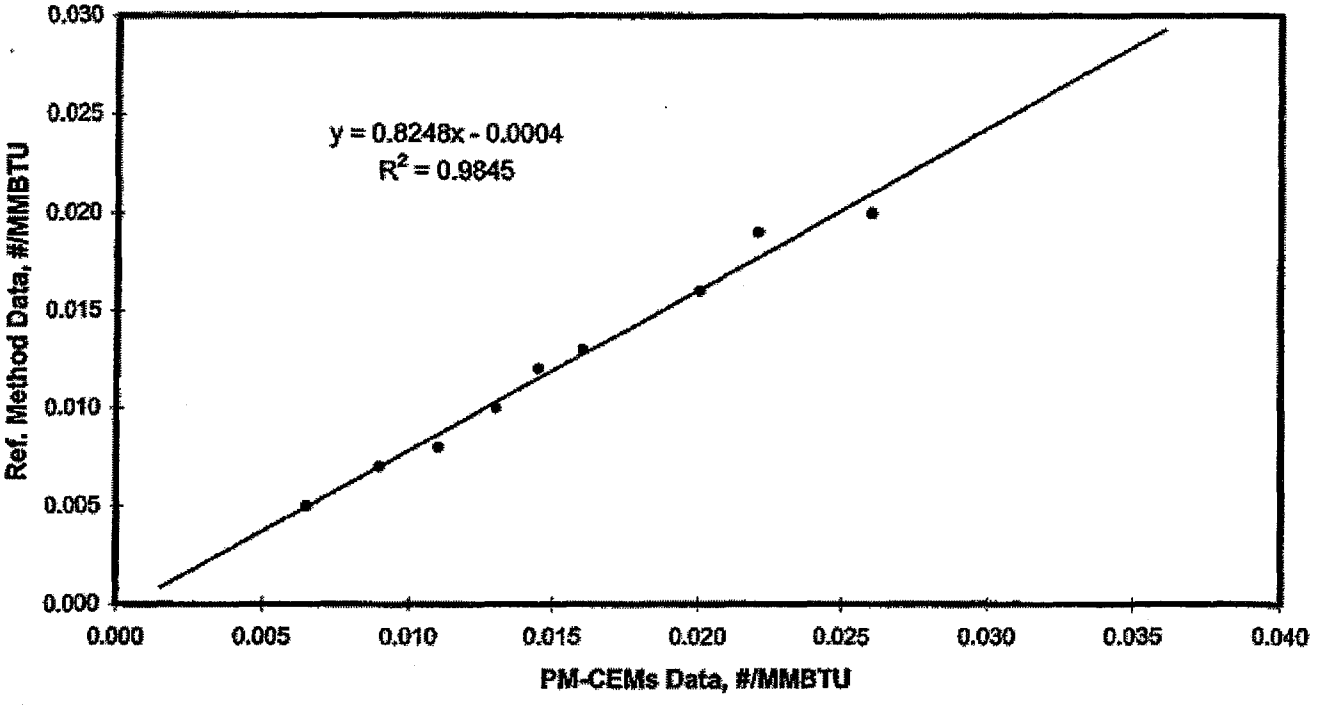
**Table 2. - Example**

| Date | Run # | PM Level | Reference Method Data | PM CEMS Data |
|---|---|---|---|---|
| | 1 | 1 | 0.0050 | 0.0065 |
| | 2 | 1 | 0.0070 | 0.0090 |
| | 3 | 1 | 0.0080 | 0.0110 |
| | 4 | 2 | 0.0100 | 0.0130 |
| | 5 | 2 | 0.0120 | 0.0145 |
| | 6 | 2 | 0.0130 | 0.0160 |
| | 7 | 3 | 0.0160 | 0.0200 |
| | 8 | 3 | 0.0190 | 0.0220 |
| | 9 | 3 | 0.0200 | 0.0260 |
| | | | | |
| Correlation Equation: | | | | y = .8248x - 0.0004 |
| Highest PM CEMS Reading: | | | | 0.0260 |
| Limit 1 (Highest PM CEMS X 1.25): | | | | 0.0325 |
| Limit 2 (0.9 X Emissions Limit): | | | | Calculated |

**Figure 1. Calibration Graph Example**



"Haas Dan" <Dan.Haas@kcpl.com>
05/22/2006 02:40 PM

To "'Ken Volmert'" <ken.volmert@dnr.mo.gov>
cc "Kelsay David" <David.Kelsay@me00.KCPL.com>,
"Gates Laurie" <Laurie.Gates@me00.KCPL.com>,
"Brown Gary" <Gary.Brown@me00.KCPL.com>,
"May Pat" <Pat.May@me00.KCPL.com>,
"Ling Paul" <Paul.Ling@me00.KCPL.com>
Subject RE: CAM Plans

Ken,
I am attaching a copy of the latest schedule for the Montrose CAM plan, as well as, a draft copy of the QA/QC plan document. You will note that the QA plan calls for daily calibrations, Quarterly Absolute Correlation Audits and a Response Correlation Audit every three years. These are our suggestions for the proper QA/QC requirements for the CAM and Title V Operating permits. Please let me know if you would like to discuss this further.

SCHEDULE

April 7-17 Install stratification test ports on all three ducts.

Week of May 22nd Have stratification tests completed on all 3 unit duct (Burns and Mac).

July 1st Have Particulate Monitors on site; also will have cables, conduit, communication equipment, etc. ready to go. Monitor Labs will provide final QA/QC manual with monitors.

July 15th Have Particulate Monitors installed, begin testing (Burns and Mac to do testing).

September 1st Begin 30 day test period for monitors.

October 1st Monitor testing complete and reporting valid data.

The results of the testing this week will determine whether placing the monitors in the ducts will be acceptable, or whether we have to go back to looking at the stack location. This schedule is of course subject to change.

# QUALITY ASSURANCE & QUALITY CONTROL PLAN
# PARTICULATE MATTER CONTINOUS EMISSION MONITORING SYSTEM (PM-CEMS)

**MONTROSE – UNIT 1, 2, AND 3**
**ORIS 02080**
**July 24, 2006**

Prepared by:

Teledyne Monitor Labs, Inc • 35 Inverness Drive East • Englewood, CO 80112

Revision Number:_____
Date of Revision:_____

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# SECTION 1 – THE QUALITY ASSURANCE PLAN

This Quality Assurance (QA) Plan is the basis for assessing and maintaining the quality of particulate matter continous emission monitoring system (PM-CEMS) data. This QA Plan has been prepared for Kansas City Power and Light, operators of three (3) particulate matter continous emission monitoring systems at the Montrose Generating Station. Section 1 of this plan is intended to outline the basic requirements with more detailed procedures for compliance included in Section 2. Each PM-CEMS output will be used to provide a reasonable level of compliance assurance by indicating electrostatic precipitator (ESP) performance.

Table I below illustrates the PM-CEMS that have been installed at the facility.

**Table I. PM-CEMS installed and certified at KCP&L Montrose Station**

| Mfr/Model | Serial Number | Measurement Range | Location | Correlation Test Date |
|---|---|---|---|---|
| Teledyne Monitor Labs / LaserHawk 360 | TBD | TBD | Unit 1 | TBD |
| Teledyne Monitor Labs / LaserHawk 360 | TBD | TBD | Unit 2 | TBD |
| Teledyne Monitor Labs / LaserHawk 360 | TBD | TBD | Unit 3 | TBD |

The PM-CEMS are installed to comply with 10 CSR 10-3.060, Maximum Allowable Emission of Particulate Matter from Fuel Burning Equipment Used for Indirect Heating. The emission limit is 0.20 lb lb/MMBTU on a station-wide average basis, except during periods of startup, shutdown and malfunction per 40 CFR 60.8(c). The PM-CEMS will provide emissions data to help in the operation and maintenance of the ESPs installed at this facility. This QA Plan was developed from guidelines by the State of Missouri Department of Natural Resources (MDNR) and the U.S. Environmental Protection Agency.

## 1.1 QUALITY ASSURANCE POLICY, GOAL, AND OBJECTIVES

Quality Assurance can be defined as the system of activities to provide assurance that the QC is performing adequately.

A QA Plan has two functions:

(1) QA – the assessment of the quality of the data (accuracy and precision) and, (2) QC – activities that maintain or improve data quality. Both functions form a control loop. When accuracy or precision is unacceptable, QC must increase until the quality of data is acceptable.

Quality control functions are usually a series of frequent internal checks, such as system inspections, periodic calibrations, and routine maintenance. Quality assurance, on the other hand, involves less frequent external checks on data quality. These external checks may include independent system audits, third party sampling and analysis for accuracy and precision, comparison to known calibration standards or inter-laboratory audits. This Quality Assurance Plan encompasses both QA and QC functions, and whenever possible, specific activities are identified by the function that is fulfilled by the activity.

The goal of this QA program is the ongoing assessment of the particulate matter limit set in the Montrose Station Title V Operating Permit.

## 1.2 DISTRIBUTION AND DOCUMENT CONTROL

This QA Plan will be reviewed whenever changes are made to the ESP and/or PM monitoring installation as well as on an annual basis.

A revision tracking system will be provided on the front page of this document and will include:

Revision Number:_____
Date of Revision:_____

### 1.2.1 MAINTENANCE OF THE QA/QC PLAN

To properly maintain the QA Plan, the following activities are monitored:

(1) The current list of QA/QC plan holders.

(2) A continuous listing of revisions and updates of the QA/QC Plan as a result of the following:
- Changes in regulations;
- Modifications or improvements of QA/QC procedures;
- Changes in responsible personnel or organization;
- Replacement of PM-CEMS components;
- Modifications to operating permit.

## 1.3 ORGANIZATION AND RESPONSIBILITY

Specific facility personnel are assigned responsibility for the PM-CEMS operational status instrument maintenance and system control. The following are provided as a

guideline, which organize responsibilities for the operation and maintenance of a PM-CEMS.

### 1.3.1 PLANT MANAGER

Is responsible for reviewing and signing all quarterly reports. The Plant Manager has the ultimate responsibility for all violations.

### 1.3.2 ENVIRONMENTAL COMPLIANCE ADMNISTRATOR (ECA)

Has overall responsibility for the operation of the PM-CEMS, generation of appropriate reports, and correspondence with the regulatory agencies.

The ECA works closely with maintenance, operations, and instrument technicians to ensure that each PM-CEMS is operated and maintained as required. Reports all major problem associated with the PM-CEMS to the Plant Manager and the Environmental Services Department.

### 1.3.3 INSTRUMENTATION TECHNICIAN (IT)

The IT is responsible for regular inspection, maintenance/repair and associated documentation of each PM-CEMS. Communicates to facility management all PM-CEMS performance and maintenance problems. Ensures all preventive maintenance checks are performed and documented. Has responsibility for the calibration of the PM-CEMS.

## 1.4 FACILITIES, EQUIPMENT, AND SPARE PARTS INVENTORY

Each unit is equipped with an ESP to control particulate emissions. Units 2 and 3 exhaust through a common stack and Unit 1 exhausts through a dedicated stack. Continuous particulate matter monitoring will be performed on the exhaust duct of each unit following the ESP.

The PM-CEMS is wired to a programmable logic controller located in the control room and will record data in the existing Data Acquisition System as well as in the Continuous Emission Monitoring System (DAS) in the CEMS building.

### 1.4.1 PARTICULATE MATTER CONTINOUS EMISSION MONITORING SYSTEM

The particulate monitoring systems utilized are Teledyne Monitor Labs 360 particulate monitors, located on Units 1, 2, and 3 exhaust duct to the stack(s). Measurement of particulate concentration is accomplished by passing a beam of laser light into the duct and measuring the intensity of the backscattered light.

## 1.4.2 RECOMMENDED SPARE PARTS AND STACK DRAWINGS

A list of spare parts is included in the instrument operations manual. Stack drawings and process diagrams are also kept on site and available for review.

## 1.5 METHODS AND PROCEDURES – ANALYSIS AND DATA ACQUISITION

The PM-CEMS data acquisition system (DAS) is an automated system that records PM-CEMS data and provides readouts as one-minute averages, which are used in subsequent calculations and report preparation. Reports prepared by the system include alarm, calibration, and emission reports.

The DAS is capable of reading all values over the full range of each measurement device and creates a permanent record of all required measured and calculated data for storage, review, and reporting. A continuous readout in PM lb/mmBtu and boiler operating time are recorded in the CEMS software.

## 1.6 CALIBRATION AND QUALITY CONTROL CHECKS

The set of operation and maintenance manuals for all systems components is maintained in the CEMS shelter. These manuals provide complete descriptions of the PM-CEMS including theory, installation, operation, and maintenance.

Factory supplied filter standards are used to calibrate the instrument at a reference zero and upscale span value. These calibration standards will be maintained in accordance with the manufacturer's recommendations. Following this calibration an internal "zero-span" cycle will be initiated, thus establishing initial values for future reference. Daily "zero-span" cycles will follow with the results stored in the data system and compared with the initial values. Should either of the "zero or span" value error exceed ± 4% of the starting value, an alarm will be initiated to signal the need for recalibration of the instrument to the factory standards.

In addition a quarterly reference calibration will be performed as described in the instrument operations manual. The factory standards will be used to measure instrument response at a zero and upscale value. Should either of these readings exceed the factory standard by more than ± 4% of the full-scale measurement range, the instrument will be reset to the factory standard values. Finally, routine scheduled maintenance procedures will be established in accordance with the manufacturer's recommendations.

## 1.7 MAINTENANCE - PREVENTIVE

The preventive maintenance program for the PM-CEMS is based on the equipment manufacturer's recommended procedures.

## 1.8 SYSTEMS AUDITS

A systems audit involves a general inspection of the monitoring system. It is intended as a walk through audit and used to provide a quick assessment of the availability of data, general effectiveness of operation and maintenance, and the completeness of recordkeeping procedures. Systems audit involves the following areas:

- Administrative
  - Maintenance logs – timely, complete
  - Recordkeeping – completeness, available
  - Verify correct range values entered into the data acquisition system

- Technical
  - Printer – operational, legible printouts consistent with process conditions
  - Data system – cabinets clean, areas maintained
  - Monitor enclosure – clean, all systems operational
  - Purge air blowers – operational

## 1.9 PERFORMANCE AUDITS

The purpose of Procedure 2 is to establish the minimum requirements for evaluating the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by the particulate monitor continuous monitoring system. Procedure 2 applies to PM-CEMS used for continuously determining compliance with emission standards or operating permit limits as specified in an applicable regulation or permit. Montrose Station is using the PM-CEMS as an indicator of PM emissions and therefore will meet the frequency requirements for relative response and response correlation audits as stated below. Montrose will complete the daily zero and upscale drift checks, absolute correlation audit as suggested in Procedure 2.

### 1.9.1 ABSOLUTE CORRELATION AUDIT (ACA)

An Absolute Correlation Audit is required once each calendar quarter but no sooner than 2 months after the previous ACA. ACAs are not required in quarters in which a Response Correlation Audit (RCA) is performed.

- Challenge the PM-CEMS three times at each audit point and use the average of the three responses in determining accuracy at each audit point. Audit points are audit filters that produce particulate levels of known values.

| Audit Point | Audit Range |
|---|---|
| 1 | 0 - 20 percent of measurement range |
| 2 | 40 -60 percent of measurement range |
| 3 | 70 -100 percent of measurement range |

- Operate the PM-CEMS in the mode, manner, and range specified by the manufacturer.
- Challenge the PM-CEMS at each audit point for a sufficient period of time to ensure that the PM-CEMS response has stabilized.
- Alternate filter insertions so that no filter is measured twice in succession during the audit.
- The difference between the actual known value of the audit standard and the response of the monitor is used to assess the accuracy of the PM-CEMS.
- The beginning of the out of control period is the time corresponding to the completion of an unsuccessful ACA. The end of the out of control period is the time corresponding to the completion of the subsequent successful audit.
- During an out of control period the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability.
- The PM-CEMS is considered out of control if the required quarterly absolute correlation audit is not conducted during a calendar quarter.
- A Response Correlation Audit conducted during any calendar quarter can take the place of an ACA required for that quarter.

The criteria for excessive inaccuracy are:

- >± 10% of the average audit value or 7.5% of the applicable standard, whichever is greater (PM-CEMS is out of control).
- Two consecutive ACA failures (i.e., out of control conditions) indicates the QC procedures are inadequate or that the CEMS is incapable of providing quality data.
- Whenever excessive inaccuracies occur for two consecutive quarters, the QC procedures must be revised, modified, or the monitor replaced.

**NOTE: The ACA must be conducted using the calibration kit with the same serial number as the particulate monitor.**

### 1.9.2 RELATIVE RESPONSE AUDIT (RRA)

Perform a Relative Response Audit (RRA) annually. Perform a RRA by collecting three (3) sets of simultaneous Reference Method data and Particulate Monitor data. Determine compliance with the RRA using the criteria specified in 40CFR60, Appendix F.

The PM-CEMS is considered out of control if the required RRA is not performed at the interval as specified in the operating permit or regulation.

The RRA will be performed annually and will replace the Response Correlation Audit in the quarter when both audits are due.

## 1.9.3 RESPONSE CORRELATION AUDIT (RCA)

Perform a RCA by collecting a minimum of twelve (12) sets of simultaneous Reference Method data and Particulate Monitor data once every permit renewal (5 years). To pass an RCA the following criteria must be met

- For all 12 data points, the PM-CEMS response value can be no greater than the greatest PM-CEMS response value used to develop the correlation curve;
- For 9 of the 12 data points, the PM-CEMS response value must lie within the PM-CEMS output range used to develop the correlation curve.

The criteria for excessive inaccuracy are:

- At least 75% of a minimum number of 12 sets of PM-CEMS/reference method measurements from the test must fall within a specified area on a graph developed by the calibration relation regression line over the calibration range and the tolerance interval set at ± 25% of the emission limit.
- The specified area on a graph is (a) bounded by two lines parallel with the calibration regression line, and offset at a distance ±25% of the numerical emission limit from the calibration regression line on the y-axis and (b) traversing across the calibration range bounded by the lowest and the highest CEMS reading of the calibration test on the x-axis.

The PM-CEMS is considered out of control if the required RCA is not performed at the permit renewal interval (once every 5 years). See 2.6.2 Relative Correlation Audit for details on failure of an RCA. The RCA will replace the Absolute Correlation Audit and Relative Response Audit when done in the same quarter.

**See 10.3(8) ...perform the RCA according to the procedures for the PM CEMS correlation test described in PS-11, section 8.6, except that the minimum number of runs required is 12 in the RCA instead of 15 as specified in PS-11.**

## 1.10 CORRECTIVE ACTION PROGRAM

Whenever the PM-CEMS is found to be "out of control" the data generated from the system will not be used to demonstrate compliance with permit limits or data capture requirements. Corrective action is performed "as soon as possible" after determining the PM-CEMS is not operating within 40 CFR 60, Appendix F specifications.

Corrective action is defined as the resolution of problems that occur on a non-routine basis.

### 1.10.1 SUGGESTED CORRECTIVE ACTION

References to specific PM-CEMS troubleshooting procedures are listed in the Instrument's Operation Manual.

### 1.10.2 REQUIRED NOTIFICATIONS

Immediately after learning a PM-CEMS is non-operational, the following individuals will be notified:

- Control Room Operator – who will notify the Environmental Compliance Administrator (ECA) and/or Instrument Technician (IT);
- Instrumentation Technician – will make the PM-CEMS operational;
- ECA – will notify Environmental Services Department and regulatory agency (as required).

## 1.11 REPORTS

Documentation of QA/QC data and information is an integral part of any QA Plan. This section describes reports and other records that provide adequate documentation of QA/QC activities. The two primary means of documentation used are:

- Data Acquisition System (DAS).
- Manually prepared QA/QC forms, logs and reports.

During QA audits, the DAS will be operated to collect data in a normal fashion, and will be able to print one-minute emission values for real time comparison with audit standards. The DAS is used not only to document QA/QC data and information, but also serves as the PM-CEMS data acquisition and processing system.

A number of written QA/QC reports are needed to provide supporting documentation of the continued operation of the PM-CEMS in an acceptable manner. All reports are used to notify individuals of problems related to operation of the PM-CEMS. Completion of these reports is intended to assist in identifying the need for remedial maintenance, training, or supply action, as well as the need to revise operating procedures for this QA Plan.

# SECTION 2 – STANDARD OPERATING PROCEDURES

Quality control checks may be defined as those checks performed on a routine basis such as system inspections, periodic calibrations and routine maintenance.

**LASER SAFETY WARNING: Any person working on or auditing the particulate monitoring equipment must be adequately trained in Laser Safety and have thoroughly reviewed the operations manual due to the inherent dangers in working with Laser equipment.**

## 2.1 START-UP AND OPERATION

The Shift Foreman maintains a detailed written procedure for start-up of the equipment at the facility. The document contains the step-by-step procedures for starting up and shutting down all equipment at the facility.

## 2.2 PM-CEMS INSPECTION AND PREVENTIVE MAINTENANCE

A CEMS maintenance log is maintained in the CEMS shelter to document system operational status and record any maintenance performed. The DAS electronic file contains a record of the PM-CEMS calibration activities.

The routine inspection begins with a visual inspection of the electrical and plumbing systems and components, which includes air-lines, and support bundles, as applicable. This procedure allows early detection of accidental damage to the PM-CEMS.

The Instrument Technician will examines the data acquisition system's computer printouts to verify the computer printouts have the correct time, date, and settings as applicable. A printout of the calibrations is reviewed for excessive calibration drift on a daily basis (Monday through Friday, excepting Monday holidays). A copy of the printout is filed in the CEMS files in the shelter.

Indicator lights and alarms on the system or monitor control panel are examined next. The system indicator lights notify the technician of out-of-range conditions or other potential problems associated with the PM-CEMS. Action is initiated immediately if an indicator light is illuminated; subsequent data acquired may be suspect and will be flagged accordingly.

## 2.3 CALIBRATION PROCEDURES

The 360 calibration cycle automatically checks and corrects zero and span drift. The calibration cycle can be programmed to activate at selectable hourly intervals, manually

activated from the stack, or externally activated from the programmable logic controller or data acquisition system.

## 2.3.1 DAILY CALIBRATION CHECK

A daily calibration is performed for the PM-CEMS that is measuring and reporting particulate concentration. Typically the zero and span calibration are programmed to be performed once every 24-hours. The zero calibration is conducted at a measurement level between zero and twenty (0 – 20) percent of instrument measurement range. The span calibration is conducted at a measurement level between fifty and one hundred (50 – 100) percent of instrument measurement range. A printed copy of the daily calibration for the PM-CEMS will be filed or electronically archived. Table II below illustrates calibration ranges of the PM-CEMS.

**Table II. Recommended zero and high level calibration levels**

| Emission Point | ZERO VALUE (0 – 20% RANGE) | SPAN VALUE (50 – 100% RANGE) |
|---|---|---|
| Unit 1 | TBD | TBD |
| Unit 2 | TBD | TBD |
| Unit 3 | TBD | TBD |

## 2.3.2 DAILY PM-CEMS DRIFT ASSESSMENT AND CORRECTIVE ACTION

The PM-CEMS performs a calibration once every 24 hours. The PM-CEMS shall be adjusted when the drift exceeds twice the performance specification. The PM-CEMS are considered out-of-control when:

(1) Either the zero or span calibration drift exceeds 4 percent the applicable performance specification in 40 CFR 60 for five (5) consecutive days, or

(2) Either the zero or span calibration drift exceeds 8 percent the applicable performance specification in 40 CFR 60 for any single calibration.

Table III below illustrates out-of-control calibration drift criteria for the PM-CEMS.

**Table III. Calibration Drift Criteria**

| Monitor | Level at which CEM shall be adjusted | Level at which CEM is Out-of-Control | |
|---|---|---|---|
| | | Any one day | Any five consecutive days |
| Unit 1 | 4% | 8% | 4% |
| Unit 2 | 4% | 8% | 4% |
| Unit 3 | 4% | 8% | 4% |

If an out-of-control condition exists, corrective action will be initiated immediately. Corrective action steps are identified in the Teledyne Monitor Labs Operation and Maintenance Manual or the Analyzer Operator Manual. Corrective action steps may include: adjustment of the electronics and potentiometers, care of the optics, replacement of the dessicator and/or purge blower air filter. Calibration drift checks will be repeated following corrective action to verify the PM-CEMS meets calibration requirements and is no longer out-of-control.

During an out-of-control period, the data collected by the PM-CEMS will not be used in determining particulate emissions compliance; nor will it be counted toward meeting the minimum data availability requirements.

## 2.4 PREVENTIVE MAINTENANCE PROCEDURES

The recommended maintenance schedule is used initially as a guideline and then adjusted for the application following actual field experience. Preventive maintenance checks and procedures are identified in the Maintenance and Trouble Shooting Section of the analyzer Operator Manual.

Some items in the recommended periodic maintenance chart, such as filter changes, will not exhibit a failure condition until probable damage to other components has resulted. These items require special attention for determining replacement frequency. Close and continuous observation of the operating characteristics of the system, with particular notation of any shift, either sudden or prolonged, in one direction of any of the many visual indicators in the system, should prompt a maintenance response and prevent loss of data and/or equipment damage.

The system's equipment alarms are indications that maintenance is required. They do not necessarily indicate the data is invalid. However, they do indicate that the system is operating outside of a design tolerance and inaccurate data and equipment damage will occur if the system is allowed to continue operation with the problems. For this reason, the alarms are exercised on a regular basis to assure that they are operational.

One of the best indications of system performance is the validity of the data it is generating. Daily scrutiny of the daily calibration results will indicate whether or not there is a need for maintenance.

## 2.5 CORRECTIVE MAINTENANCE PROCEDURES

A trouble-shooting section is included in each analyzer Operator Manual.

Zero and calibration drift checks will be conducted immediately prior to any maintenance, if possible. Additionally, zero and calibration drift checks will be conducted immediately following any maintenance. If the post-maintenance zero or calibration drift checks show drift in excess 4 percent of the applicable performance specifications, recalibration is conducted in accordance with the Operator Manual.

## 2.6 PERFORMANCE AUDIT PROCEDURES

### 2.6.1 ABSOLUTE CORRELATION AUDIT (ACA)

ACAs are required on a quarterly basis, unless an RCA is conducted in that quarter. The ACA is completed and the results are determined using the procedures and calculations contained in 40 CFR 60, Appendix F (Equation 2-1, to this document). Acceptable ranges for the ACA filters are included in Table IV.

**TABLE IV. ACA Audit Filters**

| Emission Point | LOW (0 – 20% of Range) | MID (40 – 60% of Range) | HIGH (70 – 100% of Range) |
|---|---|---|---|
| Unit 1 | TBD | TBD | TBD |
| Unit 2 | TBD | TBD | TBD |
| Unit 3 | TBD | TBD | TBD |

For EACH Audit

1. Record the requested data in the appropriate blocks on the data sheet(s) for the analyzer(s) being checked. Each analyzer should have its own data sheet.

2. Open the optical head on the particulate monitor.

3. Install the calibration jig onto the optical head.

4. Alternately insert each of the 3 known particulate standards into the calibration jig. Leave each filter in place for 5 minutes to ensure stable readings. Repeat this process until 3 readings have been made with each filter.

5. Uninstall the calibration jig from the optical head.

6. Close the optical head so that the instrument is reading process conditions again.

7. Calculate and record, to the hundredth decimal place, the average of the monitor's responses (A) for each level of calibration filter (high-, mid- and low-)

8. Using the equations in Appendix F, Equation 2-1, calculate the mean value and correlation accuracies for each particulate level.

The monitor passes the ACA if, at all three levels of filters, the percentage difference is ± 10.0 percent of the average audit value or the percentage difference ± 7.5 percent of the applicable particulate standard, whichever is greater. If these criteria are not met at

any level, the monitor is considered out-of-control. Indication will be made on the data sheet(s) whether the monitor(s) passed or failed the calibration error test.

## 2.6.2 RELATIVE RESPONSE AUDIT (RRA)

The Relative Response Audit requires the support of an independent stack sampling team. Three (3) simultaneous measurements are taken by the contracted test team and the particulate monitor in accordance with the reference methods specified in 40CFR60, Appendix B, Performance Specification 11. It is recommended that the test team perform duplicate measurements to ensure the maximum accuracy of the sampling.

The RRA will be conducted annually unless an RCA is completed during that same period then an RRA will not be required.

The monitor passes the RRA if all of the following occur:

(1) The response from all three measurements is less than the highest response used to generate the correlation curve,
(2) At least two of the three responses lie within the PM-CEMS output range used to develop the correlation curve, and
(3) At least two of the three responses fall within the area specified in the correlation curve and defined as the regression line ± 25% of the numerical emission limit.

## 2.6.3 RELATIVE CORRELATION AUDIT (RCA)

The Relative Response Audit requires the support of an independent stack sampling team using procedures for the PM-CEMS correlation test described in PS-11, section 8.6. The RCA will be conducted once every permit renewal (5 years) period. The RCA will replace the RRA and ACA when required in the same period.

The correlation test includes:

(1) paired reference method trains for collecting manual PM data to identify and screen the reference method data for imprecision and bias;

(2) test runs may be shorter than 60 minutes in duration (e.g., 20 to 30 minutes);

(3) convert the reference method results to units consistent with the conditions of the PM CEMS measurements (e.g., mg/acm);

(4) during each test run coordinate process operations, reference method sampling and PM CEMS operations to ensure that the process is operating at the targeted conditions

a. coordinate the start and stop times of each run between the reference method sampling (if batch sampling start the reference method at the same time as the PM CEMS sampling);
b. note the times for port changes (and other periods when the reference method sampling may be suspended) on the data sheets (to make any required adjustments);
c. properly align the time periods for the PM CEMS and the reference method measurements to account for the PM CEMS response time;
   i. conduct a minimum of 12 sets of CEMS and reference method measurements – additional measurements may be completed and rejected but a minimum of 12 sets is required;
   ii. report all data, including rejected data;
   iii. up to five test runs may be rejected without explanation;
   iv. explicit explanations are required for greater than five rejected runs;

(5) simultaneous PM CEMS and reference method measurements must be performed in a manner to ensure that the range of data that will be used to establish the correlation for the PM CEMS is maximized. First attempt to maximize the correlation range by following the procedures described in 5 (i) through (iv) (this section). If the three levels described in (i) through (iv) cannot be achieved, use the procedures in section 8.6(5);
   i. attempt to obtain the three different levels of PM mass concentration by varying process operating conditions, varying PM control device conditions, or by means of PM spiking;
   ii. the three PM concentration levels used in the correlation tests must be distributed over the complete operating range experienced by the source;
   iii. at least 20 percent of the minimum 12 measured data points should be contained in each of the following levels:

| Correlation Test /RCA | |
|---|---|
| Level 1 | from no PM (zero concentration) emissions to 50 percent of the maximum PM concentration |
| Level 2 | 25 to 75 percent of the maximum PM concentration |
| Level 3 | 50 to 100 percent of the maximum PM concentration |

   iv. although the above levels overlap, only apply individual run data to one level;

(6) if three distinct levels of PM concentration cannot be obtained, perform correlation testing over the maximum range of PM concentrations that is practical for the PM CEMS;

(7) ensure that the range of the data used to establish the correlation for the PM CEMS is maximized by the following:
a. zero point data for in-situ instruments is obtained by removing the instrument from the stack and monitoring ambient air on a test bench or

b. perform a manual reference method measurement when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when the process is not operating, but the fans are operating) or
c. if neither of the steps are possible, estimate the monitor response when no PM is in the flue gas (e.g., 4 mA = ) mg/acm).

(8) Failure of an RCA requires the following actions:
a. Combine RCA data with data from the active PM-CEMS correlation and perform the mathematical evaluations defined in PS-11 for development of a PM-CEMS correlation, including examination of alternate correlation models (i.e., linear, polynomial, logarithmic, exponential, and power). If the expanded data base and revised correlation meet PS-11 statistical criteria use the revised correlation;
b. If the criteria specified above (in a. above) are not achieved, develop a new PM-CEMS correlation based on revised data. The revised data set must consist of the test results from only the RCA. The new data must meet all requirements of PS-11 to develop a revised PM-CEMS correlation for 12 sets. The PM-CEMS is considered to be back in controlled status when the revised correlation meets all of the performance criteria specified in section 13.2 of PS-11;
c. If the actions specified above (in a. and b.) do not result in an acceptable correlation, evaluate the cause(s) and comply with the actions below within 90 days after the completion of the failed RCA:
    i. Completely inspect the PM CEMS for mechanical or operational problems, repair the PM CEMS and repeat the RCA;
    ii. If you must relocate the PM CEMS to a more appropriate measurement location perform a new correlation test according to the procedures specified in PS-11;
    iii. The characteristics of the PM or gas in the flue gas stream may have changed such that the PM CEMS technology is no longer appropriate. If this is the case, install a PM CEMS with measurement technology that is appropriate for the flue gas characteristics. Perform a new correlation test according to the procedures specified in PS-11;
    iv. If the corrective actions above (3i through 3iii) were not successful, petition the regulators for approval of alternative criteria or an alternative for continuous PM monitoring.

## 2.7 SYSTEM AUDIT PROCEDURES

System audits will be performed and recorded in the maintenance logbook. The following checks will be recorded during the system audit:

(1) Multiday calibration reports for the previous seven (7) days for all PM-CEMS. Check for trends in drift.
(2) Verification that correct span values are entered into the computer.

(3) Examination of the PM-CEMS, noting any alarms displayed and/or that the readings are consistent with monitor operation.

Quarterly system audits will be performed to:

(1) Check maintenance logbooks for timely and completed repairs;
(2) Determine the printer is operational and printout is legible, readings are consistent with process conditions;
(3) Acknowledge that the computer and monitor areas are clean and well maintained;
(4) Determination that the purge air blower is operational and alignment of opacity monitor is correct.

## 2.8 DATA BACKUP PROCEDURES

The PM-CEMS data are retained on a data acquisition and handling system (DAS). Particulate Emissions Data is backed up as part of the network or tape backup procedures used for all emissions data collected at the facility. The DAS printouts are stored in a secure area.

## 2.9 TRAINING PROCEDURES

Training is an essential element of a successful QA/QC program.

### 2.9.1 QUALITY ASSURANCE PLAN

All employees directly involved in the PM-CEMS program must review this QA/QC Plan, and the applicable EPA requirements (i.e., 40 CFR 60). As with the QA Plan, all effected employees must, at a minimum, be familiar with and review appropriate standard operating procedures .

## 2.10 DATA REPORTING PROCEDURES

The results from each audit or the routinely generated particulate data are reviewed prior to it being included into a summary report.

As part of the operating permit requirements, all PM-CEMS data are made available for review, in the form of a computerized database or printed PM lb/mmBtu logs, for 36 months. Quarterly compliance reports are submitted to the MDNR within 30 days of the ending quarter as defined in the operating permit. All data will be maintained for the life of the current Title V Operating Permit (5 years).

# III. APPENDICES

# APPENDIX A

# PM-CEMS SPECIFICATIONS

# APPENDIX B

# PERFORMANCE SPECIFICATION 11

# APPENDIX C

# CALCULATIONS

(1) Plot each of the PM CEMS and reference method data sets from an RCA or RRA on a graph based on the PM CEMS correlation line to determine if the criteria in 10.4(5) or (6) have been met
(2) Equation 2-1 is to be used to calculate ACA accuracy for each of the three audit points
(3) Equation 2-2 and 2-3 are to be used to calculate daily upscale and zero drift.

Eq 2-1 ACA Accuracy

$$\text{ACA Accuracy} = \frac{|R_{CEM} - R_V|}{R_V} \times 100$$

where:

| | | |
|---|---|---|
| ACA Accuracy | = | The ACA accuracy at each audit point in percent |
| $R_{CEM}$ | = | PM CEMS response to the reference standard |
| $R_V$ | = | The reference standard value |

EQ 2-2 Upscale Drift

$$UD = \frac{|R_{CEM} - R_U|}{R_U} \times 100$$

where:

| | | |
|---|---|---|
| UD | = | The upscale drift of PM CEMS in percent |
| $R_{CEM}$ | = | PM CEMS response to the upscale check value |
| $R_U$ | = | The upscale check value |

Eq 2-3 Zero Drift

$$ZD = \frac{|R_{CDM} - R_L|}{R_U} \times 100$$

where:

| | | |
|---|---|---|
| ZD | = | The zero (low-level) drift of PM CEMS in percent |
| $R_{CEM}$ | = | PM CEMS response of the zero check value |
| $R_L$ | = | The zero check value |
| $R_U$ | = | The upscale check value |

August 8, 2005 Proposed Procedure 2 – Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, Equation 2-1a and 2-1b not included as they are still only proposed.

# APPENDIX D

# BLANK FORMS

Note that appendices A, B, and D were not included in the CAM Test Plan above, since this information is available elsewhere.

Prepared by:

Cheryl Steffan
Environmental Engineer

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:** 012006-019 **Project Number:** 2005-05-062

**Owner:** Great Plains Energy

**Owner's Address:** 1201 Walnut Street, Kansas City, MO 64141

**Installation Name:** Kansas City Power & Light Company – Iatan Generating Station

**Installation Address:** 20250 Highway 45 North, Weston, MO 64098

**Location Information:** Platte County, S31, T54N, R36W

**Application for Authority to Construct was made for:**
Installation of a pulverized coal boiler and associated pollution control equipment (Iatan Unit 2), a fuel-oil fired auxiliary boiler, emergency fire pumps, a fuel oil storage tank and a combustion by-product landfill. Modification of an existing electrical utility steam generating unit (Iatan Unit 1) to upgrade the pollution control system and increase the heat input rate. This review was conducted in accordance with Section (8), Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required.*

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

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

JAN 31 2006

EFFECTIVE DATE

DIRECTOR OR DESGNEE
DEPARTMENT OF NATURAL RESOURCES

STANDARD CONDITIONS:

Permission to construct may be revoked if you fail to begin construction or modification within eighteen months from the effective date of this permit. The permittee should notify the Air Pollution Control Program if construction or modification is not started within eighteen months after the effective date of this permit, or if construction or modification is suspended for one year or more.

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

You must notify the Air Pollution Control Program of the anticipated date of start up of this (these) air contaminant sources(s). The information must be made available not more than 60 days but at least 30 days in advance of this date. Also, you must notify the Department of Natural Resources Regional office responsible for the area within which you are located with 15 days after the actual start up of this (these) air contaminant source(s).

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

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

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

The Air Pollution Control Program invites your questions regarding this air pollution permit. Please contact the Construction Permit Unit at (573) 751-4817. If you prefer to write, please address your correspondence to the Air Pollution Control Program, P.O. Box 176, Jefferson City, Missouri 65102-0176, attention: Construction Permit Unit.

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."*

Kansas City Power & Light Company – Iatan Generating Station
S31, T54N, R36W, Platte County, Missouri

1. Specifications, Operating Limits and Emission Limits for Coal Storage and Handling.

   A. The coal storage pile footprint area (active and in-active storage) shall not exceed 25.3 acres.

   B. The rail car unloading rate shall not exceed 4,000 tons of coal per hour, averaged over the duration of a train-set unloading event.

   C. Required Pollution Control Techniques and Equipment. The following conditions represent best available control technology (BACT) for coal storage and handling.
      1) Particulate emissions from rail car unloading shall be controlled by a baghouse.
      2) A water/chemical dust suppressant mixture shall be applied to the coal at a point between the rail car unloading hopper and the transfer tower.
      3) Kansas City Power & Light Company (KCPL) shall periodically add water and/or chemical dust suppressant to the top of the coal storage pile. A system shall be designed, constructed and operated to allow for distribution of water and/or chemical dust suppressant over the top of the coal storage pile. The use of truck-mounted pumps is acceptable provided that this method is capable of effective distribution over all areas of the storage pile.
      4) Coal conveyance and transfer systems shall be enclosed and vented to a baghouse. For any portions of the coal conveyance system that can not be enclosed and vented to a baghouse, KCPL must receive prior written authorization from the Air Pollution Control Program for an alternate control method prior to startup.
      5) A telescoping chute shall be used to drop coal from conveying equipment to the storage pile and the free fall distance from the end of the chute to the top of the coal pile shall be less than ten (10) feet.

SPECIAL CONDITIONS:

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

6) Particulate emissions from coal crushing and transfer operations shall be controlled by a baghouse.
7) Particulate emissions from the pulverized coal storage silos shall be controlled by a baghouse.
8) Housekeeping measures such as sweeping, water washing and vacuuming shall be used to clean equipment, structures and pavement to prevent or minimize generation of fugitive particulate emissions to the extent practicable.

D. Coal storage, handling and processing shall be conducted in compliance with 40 CFR Part 60, Subpart Y, *Standards of Performance for Coal Preparation Plants,* as incorporated in 10 CSR 10-6.070.

E. Coal storage, handling and processing operations shall be conducted in compliance with 10 CSR 10-6.170, *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin.*

2. Specifications, Operating Limits and Emission Limits for Iatan Unit 1 (pulverized coal boiler and the associated pollution control equipment).

A. The Unit 1 boiler shall utilize a low-sulfur (less than 1.4 lbs /MMBTU) subbituminous coal as the primary fuel. The heat input to the boiler shall not exceed 7,800 million British Thermal Units (MMBTU) per hour. No. 2 fuel oil with a sulfur content of less than 0.05 percent shall be used for light off, startup and flame stabilization. No other fuels shall be used without receiving prior written authorization from the Air Pollution Control Program.

B. KCPL shall install and effectively operate an SCR unit for the Unit 1 boiler. At least 120 days prior to initial startup, KCPL shall submit to the Air Pollution Control Program design specifications and an operations and maintenance manual for the SCR unit to include the following:
1) Catalyst type, volume and pitch;
2) Catalyst vendor;
3) Catalyst bed elevation and layout drawings;
4) Piping and instrumentation diagrams for the catalyst beds and the ammonia injection system;
5) Process flow diagrams;
6) Anticipated inlet $NO_x$ rate;
7) Anticipated ammonia injection rate;
8) Anticipated ammonia slip;
9) Anticipated flue gas temperatures through the SCR unit;

SPECIAL CONDITIONS:

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

10) A description of catalyst monitoring and replacement procedures;
11) A description of ammonia and $NO_x$ monitoring equipment and procedures; and
12) A description of equipment and procedures that will be utilized to prevent or minimize masking, plugging, poisoning, accumulation of sulfates or other deterioration in catalyst performance.

C. KCPL shall install and effectively operate a flue gas desulfurization system (wet scrubber) for the Unit 1 boiler. At least 120 days prior to initial startup, KCPL shall submit to the Air Pollution Control Program design specifications, process flow diagrams, elevation and layout drawings and an operations and maintenance manual for the flue gas desulfurization system.

D. KCPL shall install and effectively operate a fabric filtration system (baghouse(s)) for the Unit 1 boiler. At least 120 days prior to initial startup, KCPL shall submit to the Air Pollution Control Program design specifications, process flow diagrams, elevation and layout drawings and an operations and maintenance manual for the fabric filtration system.

E. The following emission limits apply to the stack that is associated with the modified Unit 1 pulverized coal boiler and associated pollution control equipment. KCPL shall not exceed the following emission limits:
1) Nitrogen Oxides ($NO_X$) - 0.10 lbs/MMBTU, based on a 30 day rolling average.
2) Sulfur Dioxide ($SO_2$) - 0.10 lbs/MMBTU, based on a 30 day rolling average.
3) $SO_2$ – 4,212 lbs/hr, based on a 24-hour rolling average.
4) $SO_2$ – 6,630 lbs/hr, based on a 3-hour block average.
5) Particulate Matter Less Than Ten Microns in Aerodynamic diameter ($PM_{10}$) – 0.0244 lbs/MMBTU, based on a 30 day rolling average. This limit includes both filterable and condensable particulate matter.
6) Filterable $PM_{10}$ – 0.014 lbs/MMBTU, based on a 3-hour rolling average.
7) Filterable Particulate Matter – 0.015 lbs/MMBTU, based on a 3-hour rolling average.
8) Opacity – 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent.
9) Carbon Monoxide (CO) - 0.16 lbs/MMBTU, based on a 30 day rolling average.
10) Volatile Organic Compounds (VOC) – 0.0036 lbs/MMBTU, test

SPECIAL CONDITIONS:

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

method average.

11) Vapor Phase Mercury – KCPL shall comply with the following three (3) limits:
   a) 39 X $10^{-6}$ lbs/gross MWh, based on a rolling annual average;
   b) The federally established emission limitation applicable to this unit; and,
   c) 210 lbs/year, total for Unit 1 and Unit 2, based on a rolling annual average.
12) Sulfuric Acid Mist ($H_2SO_4$) – 7.96 X $10^{-3}$ lbs/MMBTU, test method average – or the limit established by Special Condition 22, whichever is lesser.
13) Lead (Pb) – 5.93 X $10^{-6}$ lbs/MMBTU, test method average.
14) Hydrogen Fluoride (HF) – 33.15 lbs/hr, test method average.

Note: These emission limits include periods of start-up, shutdown and malfunction; see also 10 CSR 10-6.050 and the definitions in 10 CSR 10-6.020.

F. KCPL shall maintain the pulverized coal boiler and associated air pollution control equipment in accordance with good air pollution control practices to assure proper functioning of the equipment and minimize malfunctions.

3. Specifications, Operating Limits and Emission Limits for Iatan Unit 2 (pulverized coal boiler and the associated pollution control equipment)

A. The Unit 2 boiler shall utilize a low-sulfur (less than 1.4 lbs/MMBTU) subbituminous coal as the primary fuel. The heat input to the boiler shall not exceed 8,100 MMBTU per hour. No. 2 fuel oil with a sulfur content of less than 0.05 percent shall be used for light off, startup and flame stabilization. No other fuels shall be used without receiving prior written authorization from the Air Pollution Control Program.

B. KCPL shall install and effectively operate an SCR unit for the Unit 2 boiler. At least 120 days prior to initial startup, KCPL shall submit to the Air Pollution Control Program design specifications and an operations and monitoring plan for the SCR unit to include the information listed in Special Condition 2.B.

C. KCPL shall install and effectively operate a flue gas desulfurization system (wet scrubber) for the Unit 2 boiler. At least 120 days prior to initial startup, KCPL shall submit to the Air Pollution Control Program

SPECIAL CONDITIONS:

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

design specifications, process flow diagrams, elevation and layout drawings and an operations and maintenance manual for the flue gas desulfurization system.

D. KCPL shall install and effectively operate a fabric filtration system (baghouse(s)) for the Unit 2 boiler. At least 120 days prior to initial startup, KCPL shall submit to the Air Pollution Control Program design specifications, process flow diagrams, elevation and layout drawings and an operations and maintenance manual for the fabric filtration system.

E. The following emission limits apply to the stack that is associated with the Unit 2 pulverized coal boiler and associated pollution control equipment. KCPL shall not exceed the following emission limits:

1) $NO_X$ - 0.08 lbs/MMBTU, based on a 30 day rolling average.
2) $SO_2$ - 0.09 lbs/MMBTU, based on a 30 day rolling average.
3) $SO_2$ – 4,374 lbs/hr, based on a 24-hour rolling average.
4) $SO_2$ – 6,885 lbs/hr, based on a 3-hour block average.
5) $PM_{10}$ - 0.0236 lbs/MMBTU, based on a 30 day rolling average. This limit includes both filterable and condensable particulate matter.
6) Filterable $PM_{10}$ – 0.014 lbs/MMBTU, based on a 3-hour rolling average.
7) Filterable Particulate Matter – 0.015 lbs/MMBTU, based on a 3-hour rolling average.
8) Opacity – 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent.
9) CO - 0.14 lbs/MMBTU, based on a 30 day rolling average.
10) VOC – 0.0036 lbs/MMBTU, based on the average of 3 test runs.
11) Vapor Phase Mercury – KCPL shall comply with the following three (3) limits:
    a) $39 \times 10^{-6}$ lbs/gross MWh, based on a rolling annual average;
    b) The federally established emission limitation applicable to this unit; and,
    c) 210 lbs/year, total for Unit 1 and Unit 2, based on a rolling annual average.
12) Sulfuric Acid Mist ($H_2SO_4$) – $7.16 \times 10^{-3}$ lbs/MMBTU, test method average – or the limit established by Special Condition 22, whichever is lesser.
13) Lead (Pb) – $5.93 \times 10^{-6}$ lbs/MMBTU, test method average.
14) HF – 34.43 lbs/hr, test method average.

SPECIAL CONDITIONS:

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

Note: These emission limits include periods of start-up, shutdown and malfunction; see also 10 CSR 10-6.050 and the definitions in 10 CSR 10-6.020.

F. KCPL shall maintain the pulverized coal boiler and associated air pollution control equipment in accordance with good air pollution control practices to assure proper functioning of the equipment and minimize malfunctions.

4. Specifications, Operating Limits and Emission Limits for Ash Handling and Disposal.

A. Fly ash shall be conveyed pneumatically to a storage silo. Emissions from the storage silo shall be controlled by a baghouse.

B. A shrouded load-out spout with a vacuum return that is routed to a baghouse or fabric filter shall be used to control emissions when loading marketed fly ash from the fly ash silo to trucks that are leaving the site.

C. Fly ash that is destined for the landfill shall be conditioned to at least 20 percent moisture content before it is disposed of in the landfill.

D. Bottom ash removed from the pulverized coal boilers and destined for the on-site landfill shall be conditioned to at least 20 percent moisture prior to subsequent handling.

5. Specifications, Operating Limits and Emission Limits for Limestone Handling.

A. Particulate emissions from the limestone conveyor system (for reclamation of limestone from the storage pile) shall be controlled by a baghouse.

B. Particulate emissions from the limestone day storage bins shall be controlled by baghouses.

C. With regard to limestone handling, KCPL shall comply with the *New Source Performance Standard for Nonmetallic Mineral Processing Plants*, 40 CFR Part 60, Subpart OOO, as incorporated in 10 CSR 10-6.070.

6. Specifications, Operating Limits and Emission Limits for an Auxiliary Boiler.

A. The auxiliary boiler shall be fired with No. 2 fuel oil. The sulfur content of the fuel oil shall not exceed 0.05 percent sulfur by weight.

SPECIAL CONDITIONS:

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

B. Heat input to the auxiliary boiler shall not exceed 219.4 MMBTU/hr or 1,560 gal/hr.

C. The auxiliary boiler shall not be operated more than 876 hours per calendar year.

D. The following emission limits apply to the auxiliary boiler. KCPL shall not exceed the following emission limits:
   1) $NO_X$ - 0.100 lbs/MMBTU, test method average.
   2) $SO_2$ - 0.052 lbs/MMBTU, test method average.
   3) $PM_{10}$ - 0.024 lbs/MMBTU, test method average. (Note: This is a BACT limit, based on good combustion practices and clean fuel.)
   4) Particulate Matter – 0.030, lbs/MMBTU, test method average. (Note: This is a BACT limit, based on good combustion practices and clean fuel.)
   5) CO - 0.04 lbs/MMBTU, test method average. (Note: This is a BACT limit and the control technology selected to meet this BACT limit is good combustion practices.)
   6) VOC – 0.005 lbs/MMBTU, test method average. (Note: This is a BACT limit and the control technology selected to meet this BACT limit is good combustion practices.)

7. Specifications and Operating Limits for a Fuel Oil Storage Tank.

A. The fuel oil storage tank shall be a vertical fixed roof tank with a maximum capacity of 500,000 gallons.

B. The throughput shall not exceed 1,872,817 gallons per year. Fuel oil sulfur analysis must be conducted by KCPL or the fuel oil supplier for each shipment of fuel oil delivered to the storage tank.

8. BACT for Cooling Towers

A. The cooling towers shall be equipped with high efficiency drift eliminators that are designed to reduce drift to less than 0.0005 percent. Verification of drift loss shall be by manufacturer's guaranteed drift loss and shall be kept on site and made readily available to Department of Natural Resources' employees upon request.

B. The cooling tower(s) shall be operated and maintained in accordance with the manufacturer's specifications. Manufacturer's specifications shall be

SPECIAL CONDITIONS:

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

kept on site and made readily available to Department of Natural Resources' employees.

C. The cooling water circulation rate shall not exceed 30,096 thousand gallons per hour (= 21,970 mmgal/mth = 263,640 mmgal/yr).

D. KCPL shall keep records of the monthly and 12-month rolling averages of the amount of water circulated.

E. The total dissolved solids (TDS) concentration in the circulated cooling water shall not exceed a TDS concentration of 15,000 parts per million (ppm). A TDS sample shall be collected and the results recorded daily to verify the TDS concentration.

9. Baghouses and Other Particulate Control Devices

A. All baghouses shall be operated and maintained in accordance with the manufacturer's specifications. Each baghouse shall be equipped with a gauge that indicates pressure drop across the control device. Pressure gauges or a visual display of the pressure data (i.e., monitor or chart) shall be located such that the Department of Natural Resources' employees may easily observe them during a site visit. 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. KCPL 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.

C. KCPL 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.

D. Bin vent filters, cyclones and other particulate control devices shall be operated in accordance with manufacturer's recommendations and shall receive periodic inspection and maintenance to ensure proper operation.

SPECIAL CONDITIONS:

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

10. Haul Roads

A. Paved Roads

1) Maintenance and/or repair of the road surface shall 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) KCPL 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 Storage Pile Vehicle Activity Area

KCPL 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) KCPL 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) Water shall 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) KCPL 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 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

SPECIAL CONDITIONS:

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

control of fugitive emissions from these areas while the areas are in use, may be substituted for water application until such time as conditions warrant application of water.

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. KCPL shall record a brief description of such events in the same log that documents the 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.

C. Daily Limits for Haul Roads
KCPL shall not exceed the following daily tonnage-hauled limits:

| Description | Limit – Tons /Day |
|---|---|
| Unit 1 Fly Ash Sold | 343.3 |
| Unit 1 Bottom Ash Sold | 205.5 |
| Unit 1 Gypsum Sold | **0** |
| Unit 1 Fly Ash to Landfill | 410.9 |
| Unit 1 Bottom Ash to Landfill | **0** |
| Unit 1 Gypsum to Landfill | 592.8 |
| Unit 1 Limestone | 301.5 |
| Unit 2 Fly Ash Sold | 356.5 |
| Unit 2 Bottom Ash Sold | 213.4 |
| Unit 2 Gypsum Sold | **0** |
| Unit 2 Fly Ash to Landfill | 426.7 |
| Unit 2 Bottom Ash to Landfill | **0** |
| Unit 2 Gypsum to Landfill | 615.6 |
| Unit 2 Limestone | 330.0 |

If any parameters affecting the emission factors for the haul roads change, these daily limits are subject to amendment. The parameters affecting the haul road emission factors include the length of the haul road, surface material silt content (a default value of 8.3 % was used) and mean vehicle weight. If KCPL wants to sell gypsum or send bottom ash to the on-site landfill, a permit amendment will be required.

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

SPECIAL CONDITIONS:

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

KCPL shall preclude public access to property that is considered within the non-ambient air zone with respect to the air quality impact analysis conducted for this permit. Installation and maintenance of a fence or other physical barrier shall be the means to preclude public access. A map showing property boundary (precluded areas) can be found in January 27, 2006, *Kansas City Power and Light Prevention of Significant Deterioration Air Dispersion Modeling (Iatan I and II) Memorandum,* Figure 14. KCPL shall complete construction of the physical barrier to prior to commencing operation of the modified Unit 1 boiler.

12. Compliance Testing

A. Initial performance/certification testing shall be conducted in order to verify compliance with special conditions 2.E.(1) through (14), 3.E.(1) through (14), 6.D.(1) through (6) and to certify the accuracy of the continuous emission monitoring systems (CEMS).

B. The performance/certification tests shall be performed within 60 days of achieving the maximum production rate, but no later than 180 days after initial startup.

C. The date on which performance/certification tests are conducted shall 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. During the initial performance tests KCPL shall analyze a minimum of ten (10) representative samples of as-received coal for the following parameters:
   1) Higher Heating Value
   2) Ash
   3) Moisture
   4) Sulfur
   5) Arsenic
   6) Beryllium
   7) Cadmium
   8) Chlorine
   9) Chromium

SPECIAL CONDITIONS:

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

10) Fluorine
11) Lead
12) Manganese
13) Mercury
14) Nickel
15) Selenium

The analytical results shall be submitted with the performance test report.

E. As part of the initial performance test, KCPL shall measure emission rates for hydrogen fluoride, arsenic, beryllium, cadmium, chromium, cobalt, manganese, nickel and selenium from the pulverized coal boilers. In the event that the measured emission rates of these HAPs exceed the emission rates used in the air quality analysis, then KCPL shall be required to submit to the Air Pollution Control Program a revised ambient air quality analysis for these pollutants.

F. As part of the performance/certification test plan, KCPL shall include details regarding the CEMS to include the following:
1) Manufacturer's specifications for the analyzers,
2) A description of how the installation of sampling probes and lines was conducted to ensure compliance with applicable regulatory requirements and to ensure delivery of a properly conditioned representative sample of stack gas to the analyzer(s), and
3) A description of the testing procedures and methods that will be utilized to certify the accuracy of the CEMs.

G. 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 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.

H. With regard to the pulverized coal fired boilers, stack testing for VOC, sulfuric acid mist, lead, hydrogen fluoride, condensable particulate matter and filterable $PM_{10}$ shall be repeated at least once every 2 years and the results shall be reported to the Air Pollution Control Program. The date on which these stack 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

SPECIAL CONDITIONS:

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

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.

13. Continuous Emission Monitoring System (CEMS)/Continuous Opacity Monitoring System (COMS) – Pulverized Coal Boilers (Units 1 and 2).

A. KCPL shall install, certify, operate, calibrate, test and maintain CEMS for $NO_X$, $SO_2$, CO and any necessary auxiliary monitoring equipment in accordance with all applicable regulations. If there are conflicting regulatory requirements, the more stringent shall apply.

B. KCPL shall install, certify, operate, calibrate, test and maintain COMS for opacity in accordance with all applicable regulations. If there are conflicting regulatory requirements, the more stringent shall apply.

C. KCPL shall install, certify, operate, calibrate, test and maintain CEMS for vapor phase mercury in accordance with the Environmental Protection Agency's regulations published in the May 18, 2005 Federal Register. See 40 CFR Part 75, Appendices A, B and K.

D. KCPL shall install, certify, operate, correlate and maintain CEMS for particulate matter in accordance with the performance specification and quality assurance procedures of 40 CFR Part 60, Appendix B, Performance Specification 11 and Appendix F, Procedure 2.

E. KCPL shall install and operate a data acquisition and handling system to calculate emissions in terms of the emission limitations specified in this permit.

F. Compliance with the $NO_X$, $SO_2$ and CO emission limits for the pulverized coal boilers shall be demonstrated through the use of the required CEMS.

G. Compliance with the opacity limit for the pulverized coal boilers shall be demonstrated through the use of the required COMS.

H. Compliance with the $PM_{10}$, filterable $PM_{10}$ and filterable particulate matter emission limits for the pulverized coal boilers shall be demonstrated through the use of the required CEMS, however data gathered from the CEMS shall be adjusted as follows:

$$PM_{10} = PM_{CEM} + PM_{CONDENSIBLE} - PM_{>10}$$

SPECIAL CONDITIONS:

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

Filterable $PM_{10} = PM_{CEM} - PM_{>10}$

Where,

$PM_{CEM}$ = reported value from the particulate matter CEMS.
= Filterable particulate matter.
$PM_{CONDENSIBLE}$ = condensible particulate matter, from the stack test data.
$PM_{>10}$ = mass fraction of particulate matter greater than ten microns in diameter (from stack test data) multiplied by $PM_{CEM}$.

I. Compliance with the mercury emission limits for the pulverized coal boilers shall be demonstrated through use of the required CEMS.

14. Operational Monitoring

A. KCPL shall maintain an operational log, which shall detail each startup, shutdown, and malfunction of the pulverized coal boilers and associated pollution control systems.

B. KCPL shall maintain an operational log, which shall detail each startup, shutdown, and malfunction of the auxiliary boiler. This operations log shall include a running total of the hours per year the auxiliary boiler is on-line.

C. KCPL shall maintain an operational log for the emergency fire pumps that includes a running total of the hours per year the emergency fire pumps are in use; the total shall not exceed 200 hours.

D. KCPL shall maintain inspection, maintenance, and repair log(s) for the pulverized coal boilers and associated pollution control systems.

E. KCPL shall record the analysis of higher heating value, ash, sulfur and moisture content of every shipment of coal that is delivered to the installation, using a sample that is collected in a manner representative of the entire shipment.

F. KCPL shall analyze a representative sample of fuel oil from the fuel oil storage tank for sulfur content and higher heating value at least once per year. As an alternative, KCPL may use analytical results from the fuel vendor.

SPECIAL CONDITIONS:

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

G. KCPL shall continuously monitor and record the following process parameters:

1) Operating status of each major piece of equipment;
2) Gross kilowatts produced by the turbine(s) associated with the pulverized coal boilers and auxiliary boiler;
3) Mass feed rate of coal fed to the pulverized coal boilers;
4) Mass feed rate of fuel oil fed to the auxiliary boiler;
5) Pressure drop across the baghouses that are associated with the Unit 1 and Unit 2 pulverized coal boilers;
6) Ammonia injection rate for the SCR system;
7) Inlet $NO_x$ upstream of the SCR system;
8) Flue gas temperature in the vicinity of ammonia injection;
9) Flue gas temperature at the outlet of the SCR catalyst; and
10) Pressure drop across the SCR catalyst.

15. Recordkeeping

A. KCPL shall maintain daily records for railcar unloading operations. For each train-set unloaded, KCPL shall record the total duration of the unloading event and total mass of coal unloaded. KCPL shall calculate an average unloading rate for each unloading event to demonstrate compliance with Special Condition 1.B of this permit.

B. KCPL shall maintain daily records to demonstrate compliance with the heat input rate limitations specified in Special Conditions 2.A., 3.A. and 20 of this permit.

C. KCPL shall maintain daily records to document the tonnage of combustion by-products and limestone hauled to demonstrate compliance with Special Condition 10.C. of this permit.

D. KCPL 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.

16. Reporting

A. KCPL 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 emissions exceed the limits established by this

SPECIAL CONDITIONS:

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

permit.

B. KCPL 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 operation of equipment at this installation is not in accordance with any operational limitation or condition established by this permit.

C. KCPL shall comply with the requirements of 10 CSR 10-6.050 with regard to Start-Up, Shutdown and Malfunction Conditions.

D. KCPL 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 date in which it is discovered that emission factors used in this permit (or permit application) underestimated actual emissions.

17. Post-Construction Ambient Air Monitoring

A. KCPL shall conduct post-construction ambient air monitoring for mercury and $PM_{10}$ for a minimum of one (1) year after the pulverized coal boiler is fully operational. The monitoring period shall begin within six (6) months of the date that the pulverized coal boiler becomes fully operational. Monitoring may be discontinued upon written request and receipt of approval from the Air Pollution Control Program's Director.

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 six (6) months from the date of issuance of this permit.

D. In the event that post-construction monitoring reveals a concentration of mercury, at or beyond the property boundary, in excess of 0.14 micrograms per cubic meter, 24-hour averaging time, then KCPL shall submit a corrective action plan to the Air Pollution Control Program within 20 days of receipt of such analytical results. The corrective action plan shall specify additional control measures that will be employed to control mercury emissions from combustion by-product handling and disposal.

E. The post-construction $PM_{10}$ monitoring shall be evaluated along with the pre-construction monitoring data collected at this location. The purpose of

SPECIAL CONDITIONS:

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

this portion of the monitoring exercise is to evaluate the 24-hour $PM_{10}$ increment standard. If this evaluation demonstrates a contribution greater than the increment standard from the new project emissions, then KCPL shall submit a corrective action plan to the Air Pollution Control Program to address this finding. The corrective action plan shall identify alternatives to reduce particulate emissions/impacts. The corrective action plan will be due 30 days from a finding of excessive concentration.

18. This project will create excess netting emissions reductions totaling approximately 3,500 tons of $NO_x$ and 12,200 tons of $SO_2$. KCPL shall not use these excess emission reduction credits for $SO_2$ and $NO_x$ to avoid the applicability of BACT in any future permit applications to construct additional units at the Iatan Station or to modify Iatan Units 1 or 2 during the contemporaneous period (2001 to 2010).

19. In the event that there are conflicting requirements or specifications when comparing state and federal regulations and laws, the contents of the amended permit application and the conditions of this permit, the most stringent requirements or specifications shall apply.

20. The Unit 1 boiler heat input rate shall not exceed 6,600 MMBTU/hr. KCPL shall record and report pursuant to this condition within 90 days of issuance of this permit. After the new pollution controls (SCR, baghouse and wet scrubber) are in place and fully operational, the Unit 1 boiler heat input rate may exceed 6,600 MMBTU/hr, but shall not exceed 7,800 MMBTU/hr.

21. The purpose of this condition is to determine a more accurate heat input measurement than the method in use as of the date of this permit. KCPL may propose alternate methods for making this compliance demonstration. Prior to using any alternate methods KCPL must receive written approval from the Director of the Air Pollution Control Program. Heat input rate compliance demonstrations (see Special Conditions 2.A., 3.A. and 20) shall be accomplished using coal mass feed rate data, oil volumetric flow rate data and heating value analyses of the coal and oil. The higher heating value for coal used in the heat input rate compliance calculations shall be at least 95 percent of the 30-day rolling average of as-received coal higher heating values. The higher heating value for oil used in the heat input rate compliance calculations shall be the results of KCPL's most recent analysis, or 135,000 BTU/gallon, whichever is greater. The 95$^{th}$ percentile heat input rate for any given 24-hr period shall not exceed the rates specified in Special conditions 2.A., 3.A. and 20. The 95$^{th}$ percentile heat input rate shall be calculated at least once per hour and shall

SPECIAL CONDITIONS:

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

include data from the 24-hour period that just passed.

22. Possible Decrease in the Sulfuric Acid Mist Emission Limits for Unit 1 and Unit 2 Coal-Fired Boilers

    A. Within 90 days of the issuance of this permit KCPL shall conduct emissions tests to determine the emission rate of sulfuric acid mist from the existing Unit 1 boiler.

    B. The date on which the emissions tests are conducted shall 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.

    C. If emission rates of sulfuric acid mist from the existing Unit 1 boiler are found to be less than less than 120 lbs/hr, then new sulfuric acid mist emission limits must be developed for the modified Unit 1 boiler and the Unit 2 boiler.

    D. The new emission limits for the modified Unit 1 boiler and Unit 2 boiler, combined total, shall be less than the average emission rate determined by the existing Unit 1 emissions test.

    E. If the approach described by items A. through D. of this Special Condition is not workable, then a best available control technology analysis (BACT) shall be conducted for sulfuric acid mist. If this turns out to be the case, the BACT analysis must be reviewed and approved by the Air Pollution Control Program prior to modification of the Unit 1 boiler or start up of the Unit 2 boiler.

23. KCPL shall correct the emission inventory questionnaires for the years 2003 and 2004 with respect to the haul road emissions associated with fly ash sales. The corrections and associated fees shall be submitted to the Air Pollution Control Program within 60 days of permit issuance.

REVIEW OF APPLICATION FOR AUTHORITY TO CONSTRUCT AND OPERATE
SECTION (8) REVIEW
Project Number: 2005-05-062
Installation ID Number: 165-0007
Permit Number: 012006-019

Kansas City Power & Light Company
Iatan Generating Station
20250 Highway 45 North
Weston, MO 64098

Complete: July 29, 2005
Reviewed: May–October 2005

Parent Company:
Great Plains Energy, Inc.
1201 Walnut Street
Kansas City, MO 64141

Platte County, S31, T45N, R36W

REVIEW SUMMARY

- Kansas City Power & Light Company (KCPL) has applied for authority to construct a new pulverized coal-fired boiler at the existing Iatan Generating Station. KCPL also intends to modify the existing Unit 1 generating unit to increase the heat input and upgrade the pollution control system. Further details about the intended new construction and modifications are presented in the Project Description.

- 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 Iatan Unit 2 pulverized coal fired boiler.

- 40 CFR Part 60, Subpart D, *Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced after August 17, 1971,* is applicable to the Iatan Unit 1 pulverized coal-fired boiler.

- 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.

- 40 CFR Part 60, Subpart OOO, *Standards of Performance for Nonmetallic Mineral Processing Plants,* applies to limestone handling processes.

- 40 CFR Part 60, Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units,* applies to the auxiliary boiler.

- On May 18, 2005, the Environmental Protection Agency (EPA) published in the Federal Register a final rule entitled *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units.* This rule, otherwise

known as the Clean Air Mercury Rule, established emission limitations for vapor phase mercury for new coal-fired utility units and it also created a market-based cap and trade system for mercury emissions. The cap and trade system applies to both existing and new coal-fired utility units. The vapor phase mercury emission limitation established in the Clean Air Act Mercury Rule for new coal-fired utility units burning subbituminous coal and equipped with wet scrubbing is 42 X $10^{-6}$ lb/gross MWh. On October 28, 2005 EPA published in the Federal Register a reconsideration of the May 18, 2005 rule. This reconsideration contemplated an increase of the vapor phase mercury emission limitation for new coal-fired utility units burning subbituminous coal to either 66 X $10^{-6}$ lb/gross MWh or 97 X $10^{-6}$ lb/gross MWh, dependent upon the amount of precipitation that is typical for the area where the plant is located.

- On March 29, 2005 EPA published a final rule entitled *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electrical Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electrical Utility Steam Generating Units from the Section 112(c) List.* Through this rulemaking EPA has concluded that it is no longer appropriate or necessary to regulate coal- and oil- fired utility units under section 112 of the Clean Air Act and has removed such units from the 112(c) list.

- 10 CSR 10-6.060(9) is the section of the State construction permits rule that applies to major sources of hazardous air pollutants. Before EPA's rulemaking of March 29, 2005, a Section (9) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs) would have been required as part of this permitting process. However, there is an exemption at Subsection (C) of Section (9) that states the following:

  *The requirements of section (9) of this rule do not apply to-*

  1. *Electrical utility steam generating units unless they are listed on the source category list established in accordance with section 112(c) of the Clean Air Act; or*
  2. *Research and development activities.*

  Accordingly, a case-by-case MACT analysis is no longer required for HAPs such as mercury, hydrochloric acid and hydrogen fluoride.

- In a letter to the Air Pollution Control Program dated December 9, 2005 KCPL volunteered to comply with a mercury limit of 210 lbs/year for Units 1 and 2 combined.

- This review was conducted in accordance with Sections (6) and (8) of 10 CSR 10-6.060, *Construction Permits Required.* This project is considered as a major modification to KCPL's Iatan power plant. Net emissions increases from this project are above Prevention of Significant Deterioration (PSD) significant emission rates for CO, particulate matter, $PM_{10}$, and VOC.

- The Best Available Control Technology (BACT) requirements apply to the pollutants CO, particulate matter, $PM_{10}$, and VOC.

- Due to the addition of selective catalytic reduction for $NO_x$ control and a wet scrubber for $SO_2$ control on the Iatan Unit 1 boiler, there will be a net emissions decrease for $NO_x$, $SO_2$ and sulfuric acid mist for this project. See the Netting Analysis section of this permit review document for further detail.

- This installation is located in Platte 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 27 - *Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input.*

- Air quality modeling for this project was performed to determine the ambient impact of air pollutants. Based upon the air dispersion modeling reviewed by the Air Pollution Control Program staff, the study submitted by KCPL is complete and demonstrates that KCPL will not contribute to any violation of the National Ambient Air Quality Standards (NAAQS) or available increment.

- There are no currently applicable State or Federal laws or regulations that allow any limitation on $CO_2$ emissions for this project.

## INSTALLATION DESCRIPTION

KCPL has applied for the authority to install a pulverized coal boiler, an auxilliary boiler, associated storage, handling and pollution control equipment, a fuel oil storage tank and a landfill, all adjacent to the existing Iatan Generating Station (Installation ID Number 165-0007). The existing installation consists of a pulverized coal boiler with an electrostatic precipitator, coal and ash handling facilities and an ash pond. The existing boiler is a dry bottom, wall-fired unit utilizing subbituminous coal as the primary fuel. Fuel oil (Number 1, Number 2 and used oil) is used for start-up, and as back-up fuel. The installation received a permit from EPA in 1977 and began operation in 1980. In 1993 the Air Pollution Control Program issued a construction permit for a de minimis change at this installation which involved a decrease in the amount of power delivered to the electrostatic precipitator (Permit Number 1293-004). A Part 70 Operating Permit (Permit Number OP1999160) was issued by the Air Pollution Control Program in October 1999. KCPL submitted a Part 70 Permit renewal application in October 2004. The application is currently awaiting technical review.

## PROJECT DESCRIPTION

KCPL plans to install a new pulverized coal boiler with a maximum heat input of 8,100 MMBTU/hr. The permit application indicates that the boiler will be either an opposed-wall-fired or tangentially-fired dry-bottom boiler combusting low sulfur subbituminous coal as the primary fuel, and Number 2 fuel oil for start-up. The steam produced as a result of fuel combustion will be routed to a turbine. The turbine/generator is expected to have a nominal gross electric output of approximately 930 megawatts. Pollution control devices for the new pulverized coal boiler will include SCR with ammonia

injection for $NO_x$ control, a baghouse for control of particulate matter and a wet scrubber for control of $SO_2$.

As part of this project KCPL plans to upgrade the pollution control system for the Iatan Unit 1 boiler and they also intend to increase the heat input rate to the boiler. The maximum hourly design rate will increase to 7,800 MMBTU/hr. The pollution control upgrade to the Iatan Unit 1 boiler entails removal of the electrostatic precipitator and replacement with a baghouse, installation of an SCR with ammonia injection for $NO_x$ control and installation of a wet scrubber for control of $SO_2$.

Other emission sources for this project include the following:

- Coal Storage and Handling

  Coal will be delivered to the site by rail, to the existing rail car unloading area. In order to meet the requirements of this permit, KCPL will be required to install a baghouse to control particulate emissions from the rail car unloading process. In the permit application, KCPL indicates that the coal will be a low sulfur subbituminous coal from Wyoming. A rotary rail car dumper will dump the coal into a below grade hopper. A system of conveyers, a rotary stacker/reclaimer and transfer towers will be used to deliver coal to storage, crushing and boiler operations. A combination of crushers and pulverizers will be used to pulverize the coal to a consistency similar to talcum powder.

- Ash Handling and Disposal

  Fly ash from the coal-fired boilers will be conveyed pneumatically to a storage silo and will subsequently be transferred to a haul truck. Fly ash that is destined for the landfill will be conditioned by mixing with water in a pug mill. Marketable fly ash will be transferred to a haul truck via a telescoping chute.

  Bottom ash from the coal-fired boilers will be placed in a storage pile and then loaded into a haul truck for delivery to off-site users (such as cement kilns), or delivered to the on-site landfill.

- Auxiliary Boiler and Fuel Oil Tank

  The auxiliary boiler will use Number 2 fuel oil and will have a maximum heat input rate of 219.4 MMBTU/hr. Operation of this boiler is limited to 876 hours per year. A 500,000 - gallon capacity above ground tank will be installed for fuel oil storage.

- Limestone Handling

  Limestone will be used for $SO_2$ scrubbing. Limestone will be delivered by truck or rail and will be placed in a storage pile and then conveyed to storage bins for use in the wet scrubbers.

- Haul Roads

Truck traffic will include limestone deliveries, combustion by-product hauling to the landfill and off-site and gypsum hauling.

- Cooling Towers

  The cooling towers will be a source of particulate emissions.

- Emergency Fire Pumps

  Two (2) emergency fire pumps will be installed as part of this project. They will utilize fuel oil and will be limited to 200 hours per year of operation. One pump will be rated at 460 horsepower and the other will be rated at 265 horsepower.

## EMISSIONS/CONTROLS EVALUATION

- Pulverized Coal-Fired Boilers

  Potential particulate matter, $PM_{10}$, CO and VOC emissions from the pulverized coal boiler are greater than PSD significant emission levels and above the levels that trigger a Section (8) review. Potential emissions of all pollutants were calculated based on a maximum heat input rate to the boilers (7,800 MMBTU/hr for Unit 1 and 8,100 MMBTU/hr for Unit 2) and continuous, around the clock operation (8760 hours annually).

  A BACT analysis was conducted on the pulverized coal boilers for particulate matter, $PM_{10}$, CO and VOC. The BACT control device for particulate matter and $PM_{10}$ was determined to be a baghouse. It is anticipated that the control efficiency for $PM_{10}$ will be greater than 99.5 percent. CO and VOC emissions will be minimized through the use of good combustion practices. Potential emissions for each of these pollutants were calculated based on each pollutant's BACT emission limit. The particulate matter, $PM_{10}$ and CO emission rates will be verified through stack testing and continuous emission monitoring. The VOC emission rates will be verified by stack testing.

  Potential emissions of $NO_x$ and $SO_2$ from the pulverized coal boilers were based on the permit limits. In order to meet the permit limits KCPL will be required to install and effectively operate SCR for NOx control and wet scrubbers for $SO_2$ control. Emission rates for $NO_x$ and $SO_2$ will be verified through continuous emission monitoring.

  Potential emissions of vapor phase mercury were based on the 210 lb/year limit proposed by KCPL. Emission rates for vapor phase mercury will be verified through continuous emission monitoring.

- Coal Storage and Handling

  $PM_{10}$ emissions will occur at several points in the storage and handling of coal. The

emission factor for $PM_{10}$ from rail car unloading was taken from EPA's Factor Information Retrieval System (FIRE) Version 6.24, SCC 30501008, with control efficiencies applied due to baghouse control. Coal transfer and conveying emission factors were predicted by an empirical formula found in EPA Document AP-42, *Compilation of Air Pollution Emission Factors*, Fifth Edition, Section 13.2.4, Aggregate Handling and Storage Piles. 99 percent control efficiency was applied at the transfer towers and coal bunker emission points that have baghouses for particulate control. The coal crushing emission factor was derived from FIRE SCC 30501010 and the AP-42 Section 13.2.4 emission factor (4 drop points) and assumed 99 percent control efficiency for the baghouse. The $PM_{10}$ emission factor for storage pile wind erosion comes from *Control of Fugitive and Hazardous Dusts*, Cowherd, et al (Equation 3-9), with a control efficiency applied due to the addition of water/chemical dust suppressant to the coal. The $PM_{10}$ emission factor for vehicular activity around the coal storage piles was obtained from AP-42, Section 11.9, *Western Surface Coal Mining* (see Table 11.9-1 for the bulldozing emission factor).

- Ash Handling and Disposal

  Ash handling and disposal $PM_{10}$ emission factors were estimated using an empirical formula from AP-42 Section 13.2.4, *Aggregate Handling and Storage Piles* (1/95).

- Auxiliary Boiler and Fuel Oil Tank

  The emission factors for $SO_2$ and CO from the auxiliary boiler were taken from AP-42 Section 1.3, *Fuel Oil Combustion* (9/98), using a sulfur content of 0.05 percent and a heating value of 140 MMBTU/$10^3$ gal. The emission factors for $NO_x$, $PM_{10}$ and VOC were based on the permit limits. Emission rates from the auxiliary boiler (for all pollutants discussed in this paragraph) will be verified through stack testing. Potential emissions from the fuel oil tank were estimated by using EPA's TANKS 4.0 software.

- Limestone Handling

  Limestone handling $PM_{10}$ emission factors were estimated using an empirical formula from AP-42 Section 13.2.4, *Aggregate Handling and Storage Piles* (1/95).

- Haul Roads

  Potential emissions of $PM_{10}$ from the haul roads were estimated from AP-42, Section 13.2.2, *Unpaved Roads* (12/03). Emissions from unpaved haul roads will be controlled either through application of chemical surfactant or watering. Emissions from paved roads will be controlled by periodic washing.

- Cooling Towers

  The cooling tower's potential $PM_{10}$ emissions were calculated assuming a total dissolved solids concentration of 15,000 parts per million (ppm) and a recirculation rate of 501,600 gallons per minute. The high efficiency drift eliminator will control

drift to 0.0005 percent, leaving a drift rate of approximately 2.5 gallons of water per minute lost from the cooling towers. For the purpose of potential emission calculations, the Air Pollution Control Program utilized an overly conservative approach where potential $PM_{10}$ emissions were assumed to be 100 percent of the total particulate matter emitted.

Table 1: Emissions Summary (tons per year)

| Pollutant | Regulatory *De Minimis* Levels | Existing Potential Emissions | Existing Actual Emissions (2004 EIQ) | Net Emissions Increase |
|---|---|---|---|---|
| $PM_{10}$ | 15.0 | Major | 359.2 | 941.6 |
| $SO_2$ | 40.0 | Major | 19219.3 | -12,198.8 |
| $NO_x$ | 40.0 | Major | 9694.3 | -3515.0 |
| VOC | 40.0 | Major | 88.5 | 164.1 |
| CO | 100.0 | Major | 738.1 | 9710.9 |
| HAPs | 10.0/25.0 | Major | 91.4 | N/D |
| $H_2SO_4$ mist | 7.0 | N/D | 587.4 | -62.1 |
| Lead | 0.6 | N/D | 0.26 | 0.13 |
| Mercury | 0.1 | N/D | 0.16 | None Expected |
| Hydrogen Chloride | 10.0 | N/D | 16.6 | N/D |
| Hydrogen Fluoride | 10.0 | N/D | 70.4 | N/D |

*N/D = Not Determined

## PERMIT RULE APPLICABILITY

This review was conducted in accordance with Sections (6) and (8) of Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required.* This project is a major modification to KCPL's Iatan power plant. Net emissions increases from this project are above PSD significant emission rates for CO, particulate matter, $PM_{10}$, and VOC.

Section (9) of 10 CSR 10-6.060 does not apply for the reasons stated in the review summary.

## APPLICABLE REQUIREMENTS

KCPL shall comply with the following applicable requirements. The Missouri Air Conservation Laws and Regulations must be consulted for specific record keeping, monitoring, and reporting requirements. 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 § 643.079(1), RSMo. 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 10-2.070
- *Open Burning Restrictions*, 10 CSR 10-2.100
- *Start-Up, Shutdown and Malfunction Conditions*, 10 CSR 10-6.050

SPECIFIC REQUIREMENTS

- *Restriction of Emission of Sulfur Compounds,* 10 CSR 10-6.260
- *Acid Rain Source Permits Required*, 10 CSR 10-6.270
- *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
- *Emissions Banking and Trading*, 10 CSR 10-6.410
- *New Source Performance Regulations*, 10 CSR 10-6.070
  - *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, 40 CFR Part 60, Subpart Da
  - *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units,* 40 CFR Part 60, Subpart Db
  - *Standards of Performance for Coal Preparation Plants,* 40 CFR Part 60 Subpart Y
  - *Standards of Performance for Nonmetallic Mineral Processing Plants,* 40 CFR Part 60, Subpart OOO

BACT ANALYSIS

## Introduction

Any new source or major modification subject to Section (8) of 10 CSR 10-6.060, *Construction Permits Required*, must conduct a Best Available Control Technology (BACT) analysis on any pollutant that has a net emissions increase above PSD significance levels. For this project, the net emissions increase for particulate matter, $PM_{10}$, CO and VOC are greater than PSD significant emission levels. Therefore a BACT analysis is required for each of these pollutants. A BACT analysis is not required for $NO_x$, $SO_2$ or sulfuric acid mist since there is a net emissions reduction for these pollutants after adding controls to the Unit 1 boiler. The BACT requirements are detailed in Section 165(a)(4) of the Clean Air Act, at 40 CFR 52.21 and Section (8) of 10 CSR 10-6.060.

BACT analyses are done on a case-by-case basis and generally utilize a "top down" approach. 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 primarily on control effectiveness, but also considering energy, environmental and economic impacts.
4. Evaluate the most effective controls – based on case-by-case consideration of control effectiveness, energy, environmental, and economic impacts.
5. Select BACT. The "top" performing technology (in terms of control effectiveness) is selected unless it can be ruled out due to technical unfeasibility, energy considerations, collateral environmental impacts or cost considerations. If the top performing control technology is selected the applicant does not have to provide cost and other detailed information for other control options. Selecting BACT also involves specification of an emission limitation that relates to effective use of the BACT control technology. In some cases (such as fugitive emission sources) it is not feasible to measure emission rates, and when this is determined to be the case, certain design, equipment, work practice, operational standards, or a combination thereof, may be prescribed instead of an emission limitation.

KCPL prepared a BACT analysis as part of the permit application – see Section 5. The Air Pollution Control Program's BACT analysis considers the information submitted by KCPL, along with additional information from various sources. The BACT analysis is summarized below.

## Particulate Matter and $PM_{10}$ Control Technologies – Pulverized Coal Fired Boilers

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

Table 2: Particulate Matter and $PM_{10}$ Control Technologies Considered

| Control Technology | Percent Reduction |
|---|---|
| Baghouse | >99.5% |
| Electrostatic Precipitator (ESP) | >99% |

Baghouses are commonly used for particulate control. A baghouse consists of filter bags suspended in a metal housing. Particulate matter in the flue gas collects on the filter bag surfaces. The dust that accumulates on the bags also serves as a filter. KCPL conducted an economic evaluation and concluded that a pulse-jet baghouse would be as effective as a reverse-gas baghouse and would have lower annualized costs, as compared to the reverse air baghouse. In July 2005 KCPL indicated that pulse-jet baghouses had been selected for this project. In September 2005 KCPL asked that the permit be written to allow either pulse-jet or reverse-gas baghouses, to allow more flexibility in the bidding process.

In a pulse-jet baghouse, the bags are supported on wire cages, and the air is filtered from the outside of the bag to the inside, leaving the dust on the outside. Bag cleaning is accomplished by blasting a short pulse of high-pressure air through a venturi nozzle into the center of the bag, causing the fabric to ripple and knock off the dust from the outside. Pulse-jet baghouses are designed as one large compartment and operate continuously. A pulse of air cleans the bags every few minutes, but the baghouse is not taken off-line during cleaning.

In a reverse-air baghouse, the air is filtered from the inside of the bag to the outside, leaving dust on the inside. Bag cleaning is accomplished by reversing the flow of air, which causes the bags to flex and shake, dislodging particles.

Both pulse-jet and reverse air baghouses are capable of achieving greater than 99.5 percent reduction in filterable particulate matter and $PM_{10}$ emissions. In addition to controlling particulate matter and $PM_{10}$ emissions, baghouses will control particulate HAP emissions. KCPL proposes to install baghouses for both of the boilers. Baghouse control will be more efficient than the existing electrostatic precipitator for Unit 1 – the increased efficiency applies to particulate matter, $PM_{10}$ and $PM_{2.5}$. Baghouses are more efficient than electrostatic precipitators with regard to $PM_{2.5}$.

Baghouse control/fabric filtration represents the top control for filterable particulate matter and filterable $PM_{10}$ emissions. BACT emission rates were determined as 0.015 and 0.014 lbs/MMBTU for filterable particulate matter and filterable $PM_{10}$, respectively. This determination was based on evaluation of information submitted by KCPL, examination of recently issued permits, review of proposed amendments to the new source performance standards and the anticipated efficiency of the pulse-jet and reverse-air baghouses.

In addition, the pulverized coal boilers have BACT emission limitations that account for the condensable fraction of $PM_{10}$ (primarily sulfuric acid mist). These limits are consistent with recent permitting actions.

## CO Control Technologies – Pulverized Coal- Fired Boilers

Table 3 lists the possible control technologies (in no particular order) for CO emissions from the pulverized coal-fired boilers.

Table 3: CO Control Technologies Considered

| Control Technology |
|---|
| Catalytic Oxidation |
| $SCONO_X$ |
| Good Combustion Practice |

**Catalytic Oxidation**
Catalytic oxidation is 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 exhaust gas. 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 require the catalyst to be installed upstream of the wet scrubber and fabric filter. The ash and trace elements in the exhaust stream would foul 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 the Pulverized Coal Fired Boilers**
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 0.14 lbs/MMBTU for Unit 2 and 0.16 lbs/MMBTU for Unit 1 was determined to be BACT

for CO. This determination and associated emission rate is consistent with other recently permitted pulverized coal-fired boilers.

**Selection of VOC Control Technology for the Pulverized Coal Fired Boilers**
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 VOC emission limit of 0.0036 lbs/mmBtu was determined to be BACT for VOC from the pulverized coal-fired boilers. This determination and emission rate is consistent with other recently permitted pulverized coal-fired boilers.

**$PM_{10}$ Control Technologies – Cooling Towers**

Particulate emissions occur from the cooling tower as a result of the 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 0.0005 percent drift.

**$PM_{10}$ Control Technologies – Haul Roads**

BACT for the 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 – Coal 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 coal storage piles was determined to be application of water and/or a chemical surfactant.

**$PM_{10}$ 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, transfer towers, coal unloading and reclamation system and coal crushing. The following control methods represent BACT for coal handling:

- Particulate emissions from rail car unloading will be controlled by a baghouse.
- A water/chemical dust suppressant mixture will be applied to the coal between

the rail car unloading hopper and the transfer tower.

- Coal conveyance and transfer systems will be enclosed and vented to a baghouse.
- A telescoping chute will be used to drop coal from conveying equipment to the storage pile and the free fall distance from the end of the chute to the top of the coal pile will be less than ten (10) feet.
- Coal crushing and transfer operations will be controlled by a baghouse.
- The pulverized coal storage silos will be controlled by a baghouse.
- Housekeeping measures such as sweeping, water washing and vacuuming will be used to clean equipment, structures and pavement to prevent or minimize generation of fugitive particulate emissions to the extent practicable.

**$PM_{10}$ Control Technologies – Limestone Handling Operations**

Particulate emissions from limestone reclaim operations and the limestone day storage bins will be controlled by baghouses. BACT for the limestone handling, transfer, and preparations points was determined to be the use of baghouses at these two points.

**$PM_{10}$ Control Technologies – Combustion By-Product Handling Operations**

Particulate emissions from combustion by-product transfer sources, except fly ash that is sold, will be minimized by adding water to the material prior to transfer. Fly ash collected in the baghouse will be pneumatically transferred to storage silos and will be controlled through the use of a baghouse. A shrouded load-out spout with a vacuum return that is routed to a baghouse or fabric filter will be used to control emissions when loading marketed fly ash from the fly ash silo to trucks that are leaving the site.

**BACT for the Auxiliary Boiler**

Particulate control devices are not typically installed on units firing No. 2 fuel oil due to the relatively small amount of particulate emissions and the economic infeasibility of adding control. KCPL estimated that controlling particulate emissions from the auxiliary boiler would cost $17,758 and $19,797 per ton of pollutant removed for a fabric filter and ESP, respectively.

KCPL proposed a BACT emission limit for $PM_{10}$ of 0.03 lbs/MMBTU. The applicable 40 CFR Part 63, Subpart DDDDD limit for particulate matter is 0.03 lbs/MMBTU. Note that one limit is for $PM_{10}$ and the other is for total particulate matter. Table 1.3-6 of AP-42, Section 1.3, *Fuel Oil Combustion* indicates that approximately half of the filterable particulate matter emitted will be $PM_{10}$. Table 1.3-1 has a filterable particulate matter emission factor of 0.002 lbs/gallon. So the emission factor for filterable $PM_{10}$ is 0.001 lbs/gallon. Table 1.3-2 has a condensable particulate matter emission factor of 0.0013 lbs/gallon, all $PM_{10}$. The combined emission factor for filterable and condensable $PM_{10}$ is 0.0023 lbs/gallon. For a heating value of 140,000 BTU/gallon, the calculated emission factor for $PM_{10}$ is 0.016 lbs/MMBTU.

It appears appropriate to eliminate add-on controls for particulate matter and $PM_{10}$ due to economic considerations; however, it also appears appropriate to adjust the BACT $PM_{10}$ emission limitation downward from what KCPL proposed and to add a particulate matter BACT emission limit consistent with 40 CFR Part 63, Subpart DDDDD. KCPL indicated that they have not been able to obtain vendor guarantees for a 0.020

lb/MMBTU emission rate, which was the emission rate proposed in first-cut, rough draft of this permit. A search of EPA's RACT/BACT/LAER database (see http://cfpub.epa.gov/RBLC/htm/bl02.cfm) found emission limits as low as 0.024 lbs/MMBTU for this type of boiler. With the above discussion in mind, BACT for $PM_{10}$ is use of a clean, low sulfur fuel and an emission limit of 0.024 lbs/MMBTU.

With regard to CO and VOC, BACT was determined to be the use of good combustion practices and the CO limit was adjusted downward from what KCPL proposed after consideration of the emission factors published in AP-42, Section 1.3, *Fuel Oil Combustion* and examination of EPA's RACT/BACT/LAER database.

## NETTING ANALYSIS

Emissions netting is a term that refers to the process of considering historical and prospective emissions to determine if a "net emissions increase" of a pollutant will result from proposed modifications and/or new construction at an installation. If there is a net emissions increase above PSD significance levels and the source is classified as a "major" source then PSD requirements, including the BACT analysis requirements and ambient air quality analysis requirements, apply.

For this installation, the netting analysis involved looking at the difference between potential future emissions (after all modifications and new construction is complete) and representative historical emissions (2003 and 2004 emissions from the entire installation). The most significant emissions reductions associated with this project come as a result of adding $NO_x$ and $SO_2$ controls to the Unit 1 boiler. Creditable emissions increases and decreases entered into the net emissions increase calculations came from examination of this project only; there were no other creditable emissions increases or decreases entered into the netting analysis for the contemporaneous period. The contemporaneous period is defined as the period that starts 5 years before the anticipated construction start-up date and extending until the modifications are complete and the new equipment is operational. For this installation, it is anticipated that construction will begin in early 2006 and that the modifications and new construction will be complete and ready to go on-line by 2011. Therefore, the projected contemporaneous period is 2001 through 2010.

The results of the netting analysis indicate that there will be a net emissions decrease for $NO_x$, $SO_2$ and sulfuric acid mist. For particulate matter, $PM_{10}$, VOC and CO there will be a net emissions increase above PSD significance levels. Refer to the Table 1 *Emissions Summary* and the Appendix A *Net Emission Increase Spreadsheets* for further detail.

## AMBIENT AIR QUALITY IMPACT ANALYSIS

The ambient air quality impact analysis indicates that this project will not cause ambient air concentrations above acceptable levels. The results of a preliminary impact analysis indicate that ambient air concentrations for CO will be below the modeling significance levels listed in Table 4 of 10 CSR 10-6.060(11), therefore additional analysis was not required. Ambient air concentrations for $PM_{10}$ are predicted to be greater than

modeling significance levels but below levels that would present a problem with regard to the national ambient air quality standard or PSD increment consumption. Please refer to the incorporated air dispersion modeling memo for additional information.

Note: The 3-hour and 24-hour $SO_2$ emission limitations for the Unit 1 and Unit 2 pulverized coal boilers are subject to modification dependent upon the results of an on-going ambient air quality analysis for $SO_2$. If modified, these emission limitations will be decreased, not increased.

## STAFF RECOMMENDATION

On the basis of this review conducted in accordance with Sections (6) and (8) of 10 CSR 10-6.060, *Construction Permits Required*, I recommend permit issuance, with special conditions.

Steve Jaques, P.E.
Environmental Engineer

1/27/06
Date

PERMIT DOCUMENTS

The following documents are incorporated by reference into this permit:

- The Application for Authority to Construct, dated May 2005 and received May 16, 2005, designating Kansas City Power & Light Company as the owner and operator of the installation.
- Air Pollution Control Program Internal Memorandum, dated November 2, 2005, from Kelly Robson to Steve Jaques regarding Kansas City Power & Light – Prevention of Significant Deterioration (PSD) Air Dispersion Modeling (Iatan I and II).
- Letter, with attachments, dated July 11, 2005 and transmitted by electronic mail July 13, 2005, from KCPL (Terry Eaton) to the Air Pollution Control Program (Steve Jaques) regarding Construction Permit Application for Kansas City Power & Light – Iatan Unit 2. Attachment 1 – Wet and Dry FGD Technology Description; Attachment 2 – Technical Paper – In-Stack Condensible Particulate Matter Measurements and Issues; Attachment 3 – Intermountain Power Generating Station Approval Order.
- Letter, with attachment, dated July 26, 2005, from KCPL (Terry Eaton) to the Air Pollution Control Program (Steve Jaques) regarding KCPL Iatan Unit 2 Application. Attachment A - Permit Application BACT Determination for Particulates.
- KCPL's Economic Evaluation for $PM_{10}$, transmitted by electronic mail July 29, 2005, from KCPL (Terry Eaton) to the Air Pollution Control Program (Steve Jaques).
- Letter dated August 9, 2005 and transmitted by electronic mail August 9, 2005, from KCPL (Terry Eaton) to the Air Pollution Control Program (Steve Jaques) regarding Construction Permit Application

for Kansas City Power & Light – Iatan Unit 2. Subjects: 1) Coal Train Unloading, and 2) Sulfuric Acid Mist Net Emission Increase Analysis.

- Electronic mail, with attachments, transmitted September 8, 2005, from Trinity Consultants (Michael Burkhart) to the Air Pollution Control Program (Steve Jaques) regarding Revised Process Flow Diagrams. Attachment 1 – Process Flow Diagram for Unit 2; Attachment 2 – Process Flow Diagram for Unit 1; Attachment 3 – Revised TANKS 4.0 Emissions Report.

- Electronic mail, with attachment, transmitted September 20, 2005, from KCPL (Paul Ling) to the Air Pollution Control Program (Steve Jaques) regarding Iatan PSD Rough Draft Permit. Attachment - Revised TANKS 4.0 Emissions Report.

- Air Pollution Control Program Internal Memorandum, dated January 27, 2006, from Kelly Robson to Steve Jaques regarding Revised Kansas City Power & Light – Prevention of Significant Determination (PSD) – Air Dispersion Modeling (Iatan I & II)

## Press Releases

**Maryland Department of the Environment**

*Media Contacts*

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(410) 537-3003

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**MDE Reaches Settlement with Constellation to Curb Emissions**
*Company agrees to install new technology to improve pollution control, pay $100,000 penalty*

**BALTIMORE, MD (May 24, 2007)** – The Maryland Department of the Environment (MDE) and the Office of the Attorney General today lodged a Consent Decree in Circuit Court for Anne Arundel County resolving alleged violations of air quality opacity standards at three Maryland power plants owned by Constellation Power Source Generation, Inc. The Consent Decree requires Constellation to pay a $100,000 civil penalty, pay $100,000 towards a carbon sequestration project and install an estimated $9 million in technology improvements to control pollution.

"The majority of Maryland citizens live in areas that do not meet federal air quality standards for fine particulate matter. This Consent Decree requires important reductions toward compliance with the federal 2010 deadline," said Maryland Department of the Environment Secretary Shari T. Wilson.

Opacity is a measure of visible emissions, which is used as an indirect indicator of particulate matter emissions, the pollutant of concern. Under the terms of the Consent Decree, Constellation has agreed to install new technology and upgrade existing pollution controls to reduce particulate matter and opacity at its Brandon Shores, H.A. Wagner, and C.P. Crane plants in Anne Arundel and Baltimore Counties. The new measures include: installation of coal analyzers at each plant to reduce particulate and visible emissions by optimizing coal blending and combustion; replacement of all 5,220 filter bags in the Crane Unit 1 baghouse with upgraded bags to improve particulate removal efficiency; and improvements to the particulate matter control equipment at Brandon Shores.

In addition, the Consent Decree requires early implementation of improved opacity monitoring procedures, more frequent interim testing for particulate emissions than is presently required, and installation of continuous emission monitoring systems for particulate matter at the Brandon Shores plant. Constellation estimates the total cost of the improvements will be approximately $9 million dollars.

Under the Decree, Constellation will also pay a $100,000 civil penalty to MDE and will contribute $100,000 to the University of Maryland's Blackwater Wildlife Refuge Tidal Marsh Carbon Sequestration Project to restore tidal marshlands submerged as a result of rising sea levels and evaluate the effectiveness of tidal wetlands to reduce carbon dioxide levels through sequestration.

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Robert Ballinger
Director, Office of Communications
410-537-3003

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217/782-2113 CERTIFIED MAIL

REQUEST FOR ADDITIONAL INFORMATION

March 8, 2003

Indeck-Elwood LLC
Attn: Jim Schneider
600 N. Buffalo Grove Road
Buffalo Grove, Illinois 60089

Application No.: 02030060
I.D. Number: 197035AAJ
Date Received: March 21, 2002
Subject: Electric Generation Facility
Location: Drummond and Baseline Roads, Elwood, Will County

The application for construction permit referenced above lacks information necessary to determine compliance of the proposed power plant with all applicable regulations, as required by Section 9.1 and 39 of the Environmental Protection Act, 40 CFR 52.21(n)(iii), 40 CFR 63 Subpart B, 35 IAC 201.152, and 35 IAC 201.301(d).

The application cannot be fully evaluated until the following information is supplied:

1. Demonstration of Best Available Control technology (BACT)

a. Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a "production process" that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.

Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant. This information must be presented in a manner that is consistent with USEPA guidance for BACT determinations, such as USEPA's *New Source Review Workshop Manual*, to the extent it is practicable given the nature of IGCC

and the fact that IGCC would constitute an alternate production process. The Illinois EPA also encourages Indeck to supply relevant material to provide general background on IGCC and power plant projects using IGCC.

b. With respect to emissions performance, information must be provided for both the expected emission rates achieved by plants using IGCC and the emission limitations that have actually been established as BACT for these plants. (If Indeck considers that BACT emission limitations established for projects using IGCC should also be considered to represent the expected emissions performance of IGCC, Indeck must provide support to justify its position.) Emission performance information must also be provided in terms of the emission limitations established as BACT for IGCC power plants that are under construction, if any. Readily available information must also be provided from suppliers of demonstrated IGCC technology for the levels of performance that they state is achieved with their IGCC technology.

Information on emission performance of existing IGCC plants must be accompanied by information about the fuel supply to specific plants and other information about the plants that is relevant to emissions performance. In particular, available information on the sulfur content of the fuel supply to an IGCC plant must be provided, as it would be relevant to calculation of the control efficiency being achieved for sulfur dioxide. Other available operating information must also be provided, as it is relevant to an understanding of emission data. For example, other characteristics of the fuel to the IGCC plant should be provided as they have a significant role in affecting emissions. Information of specific aspects of the operation of a plant that affect emissions, such as use of a mixture of natural gas and fuel gas, should also be provided.

Based on the above information, for each relevant pollutant, Indeck must select a level of performance or range of performance that should be considered to be representative of use of IGCC at the proposed plant. Indeck must provide its basis for selecting a particular level of control, including relevant information and justification, if a selected level of performance is not the lowest level at which an emission limitation has been established for IGCC.

Information must also be provided as necessary to allow the emissions performance of IGCC and the proposed CFB boilers to be compared in identical terms, including consideration of process efficiency. Accordingly, if emission data is generally presented in terms of pound per million Btu, as is expected, this emission data must be accompanied by information on the relative efficiency of IGCC and the proposed plant in converting fuel into electricity, to allow a fair comparison of the emissions of the IGCC and CFB boiler technology.

In addition to performance of IGCC for emissions of regulated pollutants, Indeck must identify other beneficial environmental impacts from use of IGCC as an alternative to CFB boilers. In this regard, Indeck must address whether use of IGCC, would reduce emissions of pollutants that are not currently regulated under the Clean Air Act, such as carbon dioxide and ammonia, and if such a reduction would occur, provide data on the emissions levels and emissions performance for such pollutants.

Indeck must provide a summary table for the performance of IGCC for each relevant pollutant as compared to the performance of CFB boilers. This summary must provide the performance level or emission rate for IGCC for each pollutant in the terms that such data is discussed above and the performance level or emission rate for CFB with which it should be compared. As lower emission rates is identified for particular pollutants with use of IGCC, Indeck must estimate the proposed plant's annual emissions with IGCC and the amount of emission reduction that would occur compared to use of CFB boilers. This information for annual emissions should be calculated based on realistic upper-bound estimates for operation of the proposed plant with CFB boilers and may rely upon restrictions that are inherent in the operation of a large conventional coal-fired power plant, as demonstrated at similar plants. Similar information on annual emissions and emissions reduction should be provided for pollutants for which the CFB boilers would provide lower emissions than use of IGCC.

c. The additional data on IGCC that Indeck must provide must also include cost data to support an evaluation of the economic impacts of use of IGCC at the proposed power plant. While USEPA guidance for determining BACT under the PSD rules would excuse Indeck from providing cost data for use of IGCC if, with CFB boilers, Indeck is already proposing to use the "top control alternative," the Illinois EPA is requiring cost data for use of IGCC. This is because Indeck has not yet provided detailed data in the application that would allow the Illinois EPA to conclude that CFB boilers provide superior emissions and environmental performance than IGCC. Moreover, the emissions and environmental performance of IGCC may not necessarily be clearly established, given the number of pollutants that must be considered, the nature of available emission data, and the developing nature of IGCC. Accordingly, cost data and economic impacts may have a key role in determining whether or not IGCC must be used as BACT at the proposed plant.

With respect to economic impacts, IGCC as a production process is not as readily evaluated as alternative add-on control systems, as is more commonly addressed in top-down BACT demonstrations. The comparison of IGCC and CFB boilers in terms of their costs and other impacts may be presented as a supplement to the current application and Indeck need not revise material in the existing application addressing application of different control techniques to the CFB boilers. However, Indeck must supply supporting documentation for its estimate(s) of the cost of using IGCC at the proposed plant, as use of ICGG would entail changes to both emissions units and control systems present at the plant. Similar information is also required for the cost of the plant with CFB boilers, as such information has not yet been provided. This information is required as standardized methods are not available to the Illinois EPA to review cost estimates for IGCC and CFB boilers, unlike add-on control systems for which USEPA has developed cost-estimating methods. However, as general data on the cost of IGCC is available in published literature, from existing IGCC projects or from other reliable sources, that is adequate to support a comparison with the cost for use of CFB boilers, Indeck need not conduct a comprehensive or detailed evaluation of the costs for use of IGCC at the proposed plant.

Indeck must provide cost information that is on a consistent basis so that costs of IGCC can be readily compared to those of a power plant with CFB boilers. To be consistent, the basic cost data provided for IGCC plants would be most efficiently expressed in terms of net electrical output, dollars per megawatt. As cost data is obtained from existing plants, Indeck must explain its adjustments to such data to express the data in standardized form. Indeck must also attempt to provide cost data that is representative of a complete new IGCC power plant, as a new plant is proposed for Elwood. If cost data for a specific IGCC project is not complete, as certain components for a power plant were already present at its site, Indeck may elect to identify such components and provide an estimate of the costs of those components. At the same time, Indeck must provide cost data that consistently handles different components of the plant. For example, the cost data for a solid fuel handling and storage system, which is required for both IGCC and CBC boilers, must be handled in a similar manner. If the cost data for the CBC boilers excludes this system, the cost data for the IGCC plant cannot include this system.

Cost data for use of IGCC must also be provided on an appropriate basis. Cost data should be provided in terms of capital costs, annual operating costs, and annualized costs, the forms in which cost data is normally provided for a BACT demonstration. To the extent that certain types of cost data are not readily available for IGCC in quantitative form, Indeck must explain why such data is not reasonably available, and address, as feasible, the relative costs of IGCC and CFB boilers in a qualitative manner. Indeck must also explain what is addressed by the quantitative cost data that is provided, i.e., what costing elements are included, demonstrate that the data that is provided is sufficient to compare the relative costs of IGCC and CFB boilers, and generally explain the types of costs that are not addressed by such data. As feasible, Indeck must also identify and justify any differences in the standard assumptions underlying the estimated cost data that is provided for the proposed power plant using IGCC and CFB boilers, such as differences in the capital recovery factor, contingency allowances, or standard equipment life. (The annualized operating cost is based on a standardized equipment life for the type of facility, over which time the capital cost of the facility is assumed to be amortized.)

Accompanying the detailed data on costs, Indeck must provide a summary table comparing the economic impacts associated with use of IGCC and CFB boilers for the proposed plant. While summary information would usually be provided as a single annualized cost if alternative add-on control systems were being compared, this summary may compare different aspects of the estimated cost of using IGCC and CFB boilers for the proposed plant. For each aspect of cost, Indeck must provide the costs in the terms that such data is available, as discussed above, and cost converted to and expressed as an annualized cost, with explanation. If quantitative data is not readily available for an aspect of cost, the summary table should summarize the qualitative information that has been provided for that aspect of cost.

In addition to providing information on cost and economic impacts of IGCC, Indeck must also provide information explaining why any adverse economic impacts of IGCC that it identifies should be considered

unreasonable. In this regard, an initial issue that Indeck may wish to address is whether it considers IGCC to have been successfully applied at other plants with IGCC or why these other plants should not be considered similar to the plant being proposed by Indeck. As IGCC has been applied to only a limited number of power plants, Indeck may also identify characteristics or factors that are unique to those plants that made IGCC appropriate to those plants but would not be present for the proposed plant. In addition to the above information, Indeck should identify readily available objective indicators of adverse economic impacts that it believes should be applied to the proposed plant, with supporting explanation and justification. If such an indicator is in different terms than the cost data, as discussed above, Indeck must provide the relevant data for use of IGCC in the terms of the indicator, explaining how the cost data results in such a value for the indicator or how the indicator value was otherwise determined. Indeck should further explain whether factors that it believes demonstrate that impacts are unreasonable are of general applicability (i.e., also applicable for a similar plant proposed at other locations in the United States) or are site-specific.

If Indeck considers that the level of “availability” of IGCC would be a significant factor for the economic impacts of this technology, Indeck must explain the likely consequences of “low” availability for the design and development of the proposed plant and any additional costs or monetary penalties that would result. Indeck must also provide relevant background explaining what availability is, why it is generally important for electric power plants, and other possible consequences for parties other than Indeck from low availability of the proposed plant, if any. Indeck must also address any significant advantages that would accompany use of ICGG that might compensate for its low-availability, such as the revenues from sale of sulfur recovered as a byproduct of IGCC.

d. Indeck may provide information describing additional negative environmental and energy impacts that it believes would be associated with use of IGCC, as such impacts may also be considered in making BACT determinations. In addition to narrative discussion of such impacts, accompanied by supporting material, Indeck must provide a summary table that summarizes the information that it has provided for these impacts.

2. Demonstration of Lowest Achievable Emission Rate (LAER)

Information, as discussed above in Item 1(b), is also required as related to the emissions of volatile organic material (VOM) that would accompany use of IGCC. This is because VOM emissions from the proposed plant are subject to a requirement for the Lowest Achievable Emission Rate (LAER) under 35 IAC Part 203, rather than BACT under 40 CFR 52.21. For this purpose, Indeck should also address VOM emissions from additional emission units associated with fuel gasification, which would only be present if IGCC were used.

3. Demonstration of Maximum Achievable Control Technology (MACT)

Information, as discussed above in Item 1(b), is also required as related to the emissions of hazardous air pollutants (HAP), including mercury,

that would accompany use of IGCC. This is because emissions of HAP from the proposed plant are subject to a requirement for Maximum Achievable Control Technology (MACT) under Section 112(j) of the Clean Air Act and 40 CFR 63 Subpart B, rather than BACT under 40 CFR 52.21.

Four copies of this information are needed and will serve as a supplement to your application. Failure to supply the required information specified above may require the Illinois EPA to deny this permit application.

If you have any questions concerning this letter, please contact Shashi Shah at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:JMS:

cc: Region 1

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March 19, 2003

Mr. Thomas V. Skinner
Regional Administrator
U.S. Environmental Protection Agency, Region V
77 West Jackson Boulevard, R-19J
Chicago, Illinois 60604-3507

Re: Scope of Evaluation of Best Available Control Technology (BACT)
Integrated Gasification Coal Combustion (IGCC)

Dear ~~Mr. Skinner:~~ Tom:

The purpose of this letter is to inform the USEPA of a recent action taken by the Illinois EPA in administering the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. As you know, pursuant to a delegation agreement with the USEPA, the Illinois EPA processes applications for PSD permits for sources located in Illinois.

Over the last few months, the Illinois EPA has been reviewing whether Integrated Gasification Coal Combustion (IGCC) must be considered as part of the Best Available Control Technology (BACT) demonstration supplied in the PSD application for a proposed coal-fired power plant in Illinois. We have concluded that it is appropriate for applicants for such plants to consider IGCC as part of their BACT demonstrations. In this regard, IGCC is an alternative production process that can be used with coal to produce electricity. General guidance previously provided by the USEPA states that "there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis." We have concluded that this is such a circumstance.

Attached for your information is a copy of a letter that was recently sent to Indeck-Elwood LLC, formally notifying it of the need to address IGCC as part of its BACT demonstration.