AIR PERMIT APPLICATION FOR SPRAY DRYER ABSORBER MAINTENANCE JEA – NORTHSIDE GENERATING STATION *DUVAL COUNTY, FLORIDA*

Prepared For:

Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

Prepared By:

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August 2008

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August 13, 2008

Mr. Syed Arif, P.E.
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RE: Northside Generating Station -- Request to Revise Permits
Maintenance and Repair of Spray Dryer Absorbers
Air Construction Permit No. 3100450-003-AC (PSD-FL-265) and
Title V Air Operation Permit No. 0310045-016-AV

0310045-022-AC / PSD-FL-265E

Dear Mr. Arif:

JEA appreciates your assistance in addressing operation of the Unit No. 1 and No. 2 spray dryer absorbers (SDAs) at the Northside Generating Station and hereby submits a formal request to revise both the air construction permit and the Title V air operation permit, referenced above, to clarify and confirm unit operation when a malfunction occurs on an SDA as well as during maintenance and repair activities. The attached application addresses the issues we discussed at our meeting on May 29, 2008, and reflects the requested information that JEA submitted to the Department following that meeting.

As you know, the Northside Generating Stations Unit Nos. 1 and 2 are coal and petroleum coke-fired circulating fluidized bed (CFB) units that were originally permitted under an air construction permit in 1999. The units were constructed and began operating in 2002. The primary air pollution control equipment for each of these units includes limestone injection into the boiler, a baghouse, and an SDA "polishing scrubber." As the permit provides, sulfur dioxide and acid gases are primarily controlled by injection of limestone into the CFB boiler beds. While the SDAs have been used by JEA as a cost-effective way to minimize sulfur dioxide and acid gas emissions, all of the air emission limits established in the construction permit can be achieved without operation of the SDAs.

On occasion, JEA must take the SDAs "off-line" (meaning no slurry flow) because of a malfunction or to perform needed maintenance or repairs. The permit recognizes that equipment may malfunction, and excess emissions are authorized should they occur due to an equipment malfunction. When an SDA is taken offline due to a malfunction of the SDA or because of needed maintenance or repairs, all air emission limits are being met and no excess emissions occur because the baghouse remains operational and because additional, compensating limestone is injected into the CFB boiler, the primary method of minimizing sulfur dioxide and acid gas emissions.

When an SDA is taken off-line, overall unit emissions are minimized to the greatest extent possible by continuing operation of the boiler rather than initiating shutdown of the unit. As described more fully in the attached application, the shutdown and subsequent startup of the units due to the SDAs being taken off-line for typical malfunctions, repairs, and maintenance activities would result in an unnecessary increase in emissions each year. This is primarily because the maintenance and repair activities on an SDA can be accomplished within a few hours (typically around six hours), with no increase in air emissions. On the other hand, the shutdown and subsequent startup of a unit results in excess emissions above permitted levels and takes almost 48 hours to complete. Moreover, because electricity generation from the Northside unit is reduced, compensating generating from other, typically higher-emitting, less efficient units is necessary. The potential increase in annual emissions is significant—approximately 2,710 tons—and can be avoided altogether by operation of the boilers during SDA repair and maintenance activities.

JEA has sulfur dioxide monitors in place to provide assurances that sufficient limestone is added to the boilers to compensate for the SDAs being offline, and JEA is proposing to install mercury monitors on both units that will provide assurances that the mercury limits are being achieved even without operation of the SDAs.

Because the air construction and operation permits as well as the federal rules require JEA to operate the units and associated control equipment in a manner consistent with good operating practices for minimizing emissions, because all air emission limits are achieved even without the SDAs in operation, and because the shutdown and subsequent startup of the units would result in significantly higher emissions, JEA requests clarification in the permits that taking the SDAs off-line for malfunctions, repairs, and maintenance activities while continuing to operate the boilers is appropriate and does not constitute circumvention under the permits or under Rule 62-210.650, Florida Administrative Code.

JEA appreciates the Department's careful review of the materials previously provided as well as the materials being provided in this submittal. If you or anyone else within the Department has any questions or would like any additional information to assist in your review, please contact Bert Gianazza at 904-665-6247.

At the time of the filing of this application, all units are in compliance with applicable rules and regulations. It should be noted, however, that the Department of Environmental Protection and the Jacksonville Environmental Quality Division (EQD) have recently raised compliance concerns regarding maintenance and repair activities associated with the spray dryer absorbers (also referred to as polishing scrubbers) used on Northside Unit Nos. 1 and 2 (Emission Units ID Nos. 26 and 27). Discussions among Department, EQD, and JEA representatives continue and this matter has not been resolved as of the date of the filing of this request for revision of the air construction and Title V air operation permits. If necessary, a Compliance Plan may be necessary to reflect the outcome of these discussions and final resolution of this matter.

Sincerely,

James M. Chansler

James M. Chansler, P.E., D.P.A.,
Chief Operating Officer
Responsible Official

Cc: Steve Pace, P.E., EQD

Enclosures

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Jacksonville Electric Authority (JEA)**	
2. Site Name: **Northside Generating Station**	
3. Facility Identification Number: **0310045**	
4. Facility Location... Street Address or Other Locator: **4377 Heckshire Drive** City: **Jacksonville** County: **Duval** Zip Code: **32226**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Bert Gianazza, P.E.**
2. Application Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**
3. Application Contact Telephone Numbers... Telephone: **(904) 665-6247** ext. Fax: ( )
4. Application Contact E-mail Address: **GianNB@jea.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 8/15/08	3. PSD Number (if applicable): 265 E
2. Project Number(s): 0310045-022-AC	4. Siting Number (if applicable):

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

☐ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☒ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☒ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This air construction and Title V permit revision application is for clarification of the ability to operate CFB Boiler Nos. 1 and 2 (EU Nos. 027,026) with the Spray Dryer Absorber (SDA) offline due to malfunction or maintenance/repair. JEA is proposing to limit such operation to an average of up to 12 hours per month per unit (144 hr/yr per unit). See Attachment A for further description.

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
026	CFB Boiler No. 2	AC1F	
027	CFB Boiler No. 1	AC1F	

Application Processing Fee

Check one: ☐ Attached - Amount: $____________ ☒ Not Applicable

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name :
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3.	Owner/Authorized Representative Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4.	Owner/Authorized Representative E-mail Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature Date

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1.	Application Responsible Official Name: **James M. Chansler, P.E, D.P.A., V.P., Operations and Maintenance**
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☒ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.
3.	Application Responsible Official Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**
4.	Application Responsible Official Telephone Numbers... Telephone: ( ) ext. Fax: ( )
5.	Application Responsible Official E-mail Address:
6.	Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. James M. Chansler — Signature 13 Aug 08 — Date

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff** Registration Number: **19011**	
2. Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**	
3. Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **545** Fax: **(352) 336-6603**	
4. Professional Engineer E-mail Address: **dbuff@golder.com**	

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☒, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff
Signature
(seal)

8/11/08
Date

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

ATTACHMENT A

ATTACHMENT A

1.0 INTRODUCTION

Jacksonville Electric Authority (JEA) operates the Northside Generation Station (NGS), located in Duval County, Florida. NGS consists of two circulating fluidized bed (CFB) boilers, one oil/gas-fired boiler, four oil-fired combustion turbine units, and associated ancillary equipment to produce electric power. The CFB units (Units 1 and 2) are rated at 310 [megawatts (MW)] each, while the oil/gas-fired unit (Unit 3) is rated at 564 MW. NGS currently operates under Title V operating permit no. 0310045-016-AV, issued July 5, 2006.

The CFB boiler units each have a spray dryer absorber (SDA) polishing scrubber to aid the units in meeting permitted emission limits for sulfur dioxide (SO_2) emissions to the atmosphere. At times, the SDAs must be taken off-line for normal repair/maintenance activities or due to malfunctions. During these times, all emission limits are being met, including the sulfur dioxide (SO_2) emission limits, which are achievable primarily by increasing the limestone feed rate to the CFB boilers.

Some concern exists by the Florida Department of Environmental Protection (FDEP) and the Jacksonville Environmental Quality Division (EQD) that ***any*** non-operation of the polishing scrubber could constitute "**circumvention**". Condition H.57 of the Title V permit, similar to Condition 25 of Appendix TV-5 of the Title V permit, and Rule 62-210.650, F.A.C., provides that JEA "shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly." Condition 25 and the rule language provide: "No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly."

However, it is JEA's position that the polishing scrubber must be operated only as needed to meet the SO_2 and sulfuric acid mist limits; additional limestone added to the CFBs allows JEA to avoid use of the polishing scrubber. This can be clarified in the Title V permit through a permit revision. As explained in more detail below, all emission limits are achievable without the SDAs in operation, and requiring the shutdown of the CFBs for maintenance and repairs of the SDAs results in significantly higher emissions (a potential annual *increase* of approximately 1,626 tons of emissions). Condition H.23 of the Title V permit provides that "at all times" JEA must "to the extent practicable" "maintain and operate" the CFBs including associated control equipment "in a manner consistent with good air pollution control practice for minimizing emissions." Because all emission limits are met even with the SDAs offline and because a requirement to shutdown the CFBs due to malfunctions of the SDAs, or to perform maintenance and repair activities on the SDAs, would result in the potential significant net emissions increase of 1,626 tons per year, the appropriate and required manner of operation would be to perform maintenance and repairs on the SDAs while the CFBs remain operating.

The purpose of this application is to request that the previously issued air construction permit and the current Title V operating permit be revised to recognize and clarify that the SDA polishing scrubbers should be repaired and maintained to the extent possible while the CFBs remain operational, consistent with good operating practices to minimize emissions. The remainder of this attachment presents the description of the NGS CFB units (Section 2.0), SDA polishing scrubber and its operation (Section 3.0), the effects the polishing scrubber has on emissions (Section 4.0), and proposed permit revision language (Section 5.0).

2.0 NORTHSIDE CFB UNITS OPERATION

NGS Units 1 and 2 are coal and petroleum coke (petcoke)-fired circulating fluidized bed (CFB) boilers. The units are rated at 310 MW, with a maximum heat input rate of 2,764 million British thermal units per hour (MMBtu/hr). The units include solid fuel delivery and storage facilities, limestone preparation and storage facilities (including three limestone dryers), a lime silo, aqueous ammonia storage, polishing scrubbers (the SDA), baghouses, and ash removal and storage facilities.

The NGS CFB boilers operate on the principle of combusting fuel on a fluidized bed of material. Coal or petcoke is burned within a bed of hot incombustible particles (limestone/fly ash). The particles are suspended by the upward flow of the fluidizing gas (combustion air/products of combustion) within the combustor. The coal/petcoke is ground to the appropriate particle size prior to being introduced into the CFB boiler, and therefore also burns in suspension. Due to high velocities in the CFB boiler, a portion of the limestone/fly ash is continually carried over from the bed (approximately 20 percent). Most of this material is collected in the downstream baghouse and is then recirculated back to the CFB boiler. However, a portion of this material is bled off while fresh limestone is continually added to make up the difference.

The NGS CFB boilers are each equipped with a selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide (NO_x) emissions, limestone injection to reduce sulfur dioxide (SO_2) emissions and other acid gases, fabric filter to reduce particulate matter (PM) and particulate matter less than 10 microns (PM_{10}) emissions, while maximizing combustion efficiency to limit carbon monoxide (CO) and volatile organic compound (VOC) emissions, and minimizing NO_x formation. A flow diagram of the air quality control system downstream of each unit is shown in Figure 2-1.

The use of limestone as the bed material in the CFB boiler acts to inherently control acid gas emissions, such as SO_2, hydrogen chloride (HCl), and hydrogen fluoride (HF). The SO_2 reacts with the calcined lime to form calcium sulfate, which is caught in the downstream baghouse. The downstream SDA also provides additional acid gas scrubbing. Recycled ash from the baghouse and water are mixed to a slurry, which is then sprayed into the SDA. The SO_2 reacts with the slurry to form calcium sulfite or calcium sulfate, which is also captured in the downstream baghouse. The other acid gases are captured in a similar manner.

This combination of CFB boiler and SDA allows JEA to vary the limestone injection rate into the CFB and recycled ash slurry injection into the SDA in order to control SO_2 emissions to meet permit limits. At times when limestone injection into the CFB must be limited, the slurry feed to the SDA can be increased to achieve equivalent acid gas reduction. At times when the SDA must be taken off-line for repair or maintenance, the limestone feed to the boiler can be increased to achieve the necessary acid gas reduction. Limestone and slurry feed rates are also related to the sulfur content of the fuels being burned (coal and/or petcoke). The NGS units currently burn about 90 percent petcoke and 10 percent coal on a heat input basis.

The design of the CFB boiler allows operation over a large load range even though the units are base loaded. The CFB boiler vendor (Foster Wheeler USA) has guaranteed emissions down to 50-percent load, and based upon initial demonstrations, operation at loads as low as 25 percent is achievable while still meeting performance and emission requirements.

Emission limits for the two CFB units are summarized in Table 2-1.

SO_2, NO_x, and CO emissions are measured continuously by continuous emissions monitoring systems (CEMS). Opacity is also measured continuously by a continuous opacity monitoring system (COMS). Annual compliance testing is required for PM/PM_{10} emissions. Initial stack testing was conducted for VOC, Lead (Pb), H_2SO_4, HF, and mercury (Hg).

TABLE 2-1

EMISSION LIMITS FOR CFB UNITS

Pollutant	**Emission Limits – Per Unit**
Visible emissions	10 percent opacity, 6-minute block average
SO_2	0.2 lb/MMBtu, 24-hour block average 0.15 lb/MMBtu, 30-day rolling average
NO_x	0.09 lb/MMBtu, 30-day rolling average
PM/PM_{10}	0.011 lb/MMBtu, 3-hour average
CO	350 lb/hr, 24-hour block average
VOCs	14 lb/hr, 3-hour average
Lead (Pb)	0.07 lb/hr, 3-hour average
Sulfuric Acid Mist (H_2SO_4)	1.1 lb/hr, 3-hour average
HF	0.43 lb/hr, 3-hour average
Mercury (Hg)	0.03 lb/hr, 6-hour average

Note:
lb/MMBtu = pounds per million British thermal units.
lb/hr = pounds per hour.

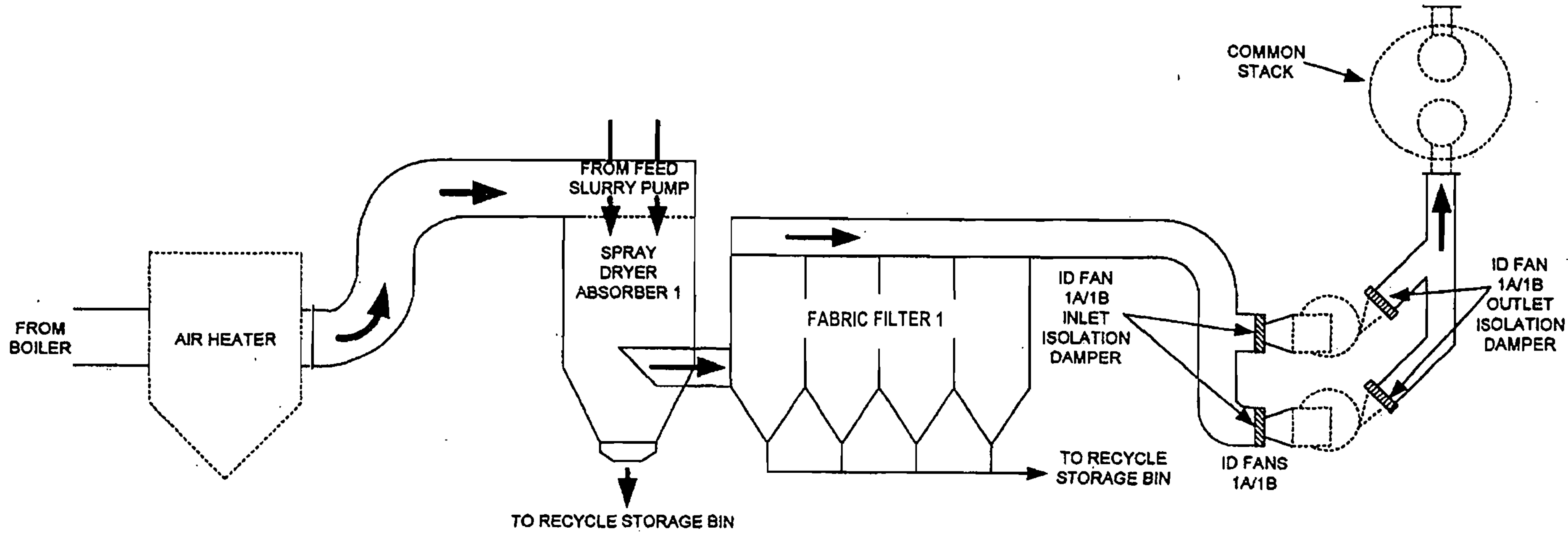


Figure 2-1
Air Quality Control System Flow Diagram
Northside Generating Station Unit 2
Figure 2-1 AQCS Overview.docx

Source: Golder, 2008.

REV.	SCALE:	
DESIGN	DB	05/06/08
CADD	SL	05/06/08
CHECK	NAV	05/07/08
REVIEW	DB	05/07/08

Golder Associates

3.0 SPRAY DRYER ABSORBER POLISHING SCRUBBER OPERATION

The SDA is referred to as a "polishing scrubber" because the primary removal of acid gases from the units is in the CFB itself (see above description). At the top of the SDA vessel, the hot flue gases, which contain limestone/fly ash carryover from the CFB, enter the vessel. A slurry consisting of captured limestone/ash from the baghouse and water is also introduced at the top of the vessel by spray nozzles. The slurry and flue gases mix, causing the water in the slurry to evaporate. Most of the remaining solids become suspended in the gas flow, and exit the SDA along with the flue gases, to be captured in the downstream baghouse.

The SDA contains a lower vessel hopper, which is a cone shaped hopper located on the bottom of the SDA vessel. This hopper acts to collect particles that fall out of the flue gas flow stream prior to the gases exiting the SDA vessel. The SDA is designed for an outlet flue gas temperature of 165 to 175 degrees Fahrenheit (°F), in order to ensure evaporation of the moisture in the slurry. Automatic controls reduce the slurry feed rate as necessary to maintain the outlet temperature above 155°F. A further description of the SDA and its operation, as contained in JEA's standard operating procedures, is presented in Appendix A.

3.1 SDA Polishing Scrubber Maintenance Events

Information on past maintenance and repair activities, including expected cause, frequency of occurrence and duration of non-operation of the SDA, is presented in Table 3-1. This information was developed from a review of the last 2 years of operation of both units. This included only events in which an SDA was out of service and the CFB unit stayed on line. Each event was recorded along with duration and notes from the operator log as to the issue. The maintenance records are typical for what JEA would expect in any given year moving forward.

Based on the analyses over the last 2 years, average SDA off-line event time is approximately 11 hours. Note that Unit 1 had an unusually long event due to start up and rework issues. This is not typical, and thus the average yearly maintenance hours excluded this event. The average hours of SDA off-line time per year is 136 hr/yr for Unit 1 and 108 hr/yr for Unit 2. Note that based on this information, JEA is requesting up to 144 hr/yr of SDA off-line time for maintenance/repair.

Review of Table 3-1 indicates that the SDA maintenance events for both Unit 1 and Unit 2 show considerable hours when the SDA was down due to vessel pluggages. When any one of the 16 nozzles on a given SDA unit has a spray pattern quality issue, the slurry discharged from the nozzle in question is not properly atomized, and therefore does not dry as designed along the flow path, resulting in wet slurry being deposited on the SDA vessel walls. The only clue as to the location of the "faulty" nozzle is a zone differential temperature (which indicates the probable zone), and the operators will pull each nozzle in that zone until the offender is located.

Once this has occurred, the deposits may be so thick that the only way to remove the deposited material is to stop spraying altogether in the SDA, initiate the impactors (vibrators), and allow the material to dry, at which time it is shed from the walls. Once this occurs, the material invariably plugs the slide gate area, which requires removal of the expansion boot at the very bottom of the SDA vessel to allow operators to rod-out the chunks of material. Spraying at this time is not allowed due to the inability to verify the quality of the ash. The quality of the ash must be verified by physically observing the ash as it comes out of the SDA emergency conveyor, which is impossible to do when the bottom is plugged. The CFB boilers are not taken off-line when maintenance steps are taken to remove the pluggage.

The QA/QC procedures JEA uses to mitigate the spray quality/pluggage events are contained in the attached document "AQCS Guidelines" (Appendix A). JEA also has a library of 18 other more specific procedures, but the AQCS Guidelines is the set of guidelines utilized on a routine basis to prevent the pluggage described.

A list of all deviations currently practiced from the original manufacturer's recommendations for operation and maintenance of the SDAs is provided in Table 3-2.

3.2 Operational and Economic Impacts of CFB Shutdown when SDA is Off-Line

Operational and economic impacts would occur to the NGS Units 1 and 2 if the CFB boilers were required to shutdown whenever the SDA polishing scrubber is off-line. Currently, the CFB units undergo a planned shutdown once per year for maintenance/repair. However, each SDA polishing scrubber is typically taken off-line for 20 or more separate occasions during an annual period. If the CFBs were required to shutdown during these periods, 20 or more shutdowns and then startups of the units would occur annually.

A potentially critical impact of numerous shutdown/startup events is the thermal cycles the units undergo during such events. Each time the boiler is shut down from full load condition, the equipment experiences a thermal cycle. Thermal cycling refers to the heating and subsequent cooling of the plant equipment. Thermal cycles as defined by the boiler vendor Foster Wheeler, are as follows:

> "Thermal cycling in a CFB is defined as any cycle of temperature within the hot loop system from the standard operating temperature (about 1700°F) to a temperature of 700°F, as measured by the bed temperature and cyclone inlet/cyclone flue gas temperatures, below the standard operating temperature (about 1700°F) and subsequent return to the standard operating temperature, or a drop in the steady water-side pressure that results in greater than 250°F change in the steady water-side saturation temperature. During these changes in temperature, considerable expansion and contraction of linings, tubes, refractory, casing, etc. occurs. To lessen the potential damage that can be caused by thermal cycling, you must minimize the number of cycles and the rate of temperature change during a cycle."

The consequences of the boiler undergoing additional thermal cycles are:

- Extended time off-line to repair the damage caused by the thermal cycle;
- Additional expense to purchase replacement refractory and compromised metal;
- Additional cost to install the repair material; and
- Due to the additional repair time needed, lost generation.

The thermal cycle issue has the potential to add several hundred thousand dollars to each outage depending upon on the extent of the damage.

It should also be recognized that JEA has a significant economic incentive to always operate the SDA polishing scrubber. Presented below is a cost analysis of the financial burden JEA incurs when the SDA polishing scrubber is off-line and additional, compensating limestone is added to the CFBs. The analysis demonstrates that it is in JEA's best interest to ensure the SDA is in service as much as possible and is operating efficiently.

The following calculations were originally performed as part of part of a hard savings analysis for a six sigma project in mid-2007; all costs have been updated to reflect current data (as of June 19, 2008). This analysis is based upon the premise that removing the SDA from operation creates the need for more SO_2 removal in the boiler, which is achieved by increasing limestone to the boiler.

- Costs associated with limestone addition to the CFB Boiler:
  - Limestone cost = $18/ton;
  - Limestone handling cost (getting the material into the boiler) = $4/ton;
  - Byproduct Disposal = $22/ton;
  - Byproduct handling and preparation cost = $4/ton;
  - 1 ton of limestone produces 1.2 tons of byproduct;
  - Average monthly total Limestone consumption for Unit 1 = 21,600 tons/month;
  - Hourly average consumption (conservative) = 30 tons per hour;
  - Total cost per ton of limestone = 18 + 4 + (1.2 × (22 + 4)) = $53/ton;
  - Total hourly cost per ton of limestone added to the boiler = 30 TPH × $53/ton = $1,590/hr;
  - Average increase in limestone flow to CFB boiler when the SDA is removed from operation = 25%;
  - 30 TPH × 125% = 37.5 TPH (increase of 7.5 TPH); and
  - 7.5 TPH × $1,590/ton of limestone = $11,925 for each hour the SDA is out of operation/unit.

If JEA were to utilize the full 144 hours per year of SDA downtime (as proposed in the new permit language) for a given unit, the cost incurred by JEA would be $1,717,200 per year ($3,434,400 for both units).

In addition, if JEA were to be required to shutdown the CFB units whenever the SDA scrubber is not operating, significant economic impacts would result in the form of lost generation. This lost generation would need to be replaced by another unit(s) within the JEA system, and likely would require burning of a more costly and less available fossil fuel such as fuel oil or natural gas.

TABLE 3-1a

SUMMARY OF SDA MAINTENANCE EVENTS, UNIT 1

Event Date	Hours Spray Dryer Off Line	Operator Log Comments	Modified by removal of 7/12/07 Event
02/25/08	15	SDA vessel pluggage	15
02/13/08	6	Recycle slurry separator failure	6
01/16/08	5	Reuse water supply line out of service	5
12/08/07	2	Voltage spike trip atomizing air compressors	2
10/11/07	4		4
09/26/07	9	SDA vessel pluggage	9
08/28/07	15	Feed slurry pumps and lines plugged	15
08/09/07	3		3
08/06/07	56	SDA vessel pluggage - colossal	56
07/12/07	144	Mix tank and SDA vessel pluggage - multiple starts and stops	
06/20/07	17	Plugged slurry return vent valves	17
06/19/07	1	Feed slurry pump plugged	1
06/11/07	15	Leak in feed slurry transfer pump discharge line	15
03/15/07	7	Plugged ring header drain line	7
02/13/07	12	SDA vessel pluggage	12
02/10/07	8	Plugged ring header drain line	8
01/04/07	7		7
11/09/06	16	SDA vessel pluggage	16
09/08/06	5	Recycle slurry tank level indicator failure	5
09/06/06	13	Leak in elbow above storage tank	13
09/05/06	6	Leak in return line	6
08/03/06	3	Replace header gauge	3
07/31/06	10		10
07/16/06	21		21
06/30/06	5		5
06/07/06	11		11
Total hours over 2 years	416		272
Average hours per year	208		136
Average hours per event	16		10.9

TABLE 3-1b

SUMMARY OF SDA MAINTENANCE EVENTS, UNIT 2

Event Date	Hours Spray Dryer Off Line	Operator Log Comments
03/13/08	27	Mix tank pluggage
03/12/08	4	
03/03/08	5	Final filter failure
01/16/08	9	Reuse water supply out of service
10/06/07	6	SDA vessel pluggage
10/05/07	2	Plugged ring header
06/08/07	4	SDA vessel pluggage
05/28/07	7	Slurry pump failure
01/08/07	27	Mix tank pluggage
12/29/06	8	SDA vessel pluggage/wet ash
08/29/06	46	Leak in the feed slurry return line
08/28/06	20	Leak in the return line
07/06/06	3	
06/11/06	5	
05/22/06	19	
05/12/06	2	
05/10/06	2	
04/25/06	8	
04/12/06	12	

Total hours over 2 years	216
Average hours per year	108
Average hours per event	11.4

TABLE 3-2
EXCEPTIONS TO MANUFACTURERS' RECOMMENDED O&M PROCEDURES

OEM BOOK OPERATION	NORTHSIDE OPERATION
Use of pebble lime system for slaking and manufacturing of lime slurry	Recycle fly-ash is utilized in lieu of the pebble lime system
Maximum allowable operating temperature is 375°F (baghouse)	Set maximum temperature to 325°F
SDA Gas Outlet temperature range of 155 - 175°F	Set the SDA Gas outlet temperature to 175°F minimum
Nozzles must be removed once every week for cleaning and inspection	Clean nozzles on a daily basis
Slurry flow to the SDA is initiated after stable operation in CFB achieved with a minimum CFB load of 25% MCR and a minimum	Set the startup of the SDA spraying to inlet Flue Gas Temperature of 265°F
The SDA should be shutdown when CFB load drops below 25% MCR or the SDA inlet temperature drops below 240°F	Set the shutdown of the SDA to be when SDA inlet temperature drops below 265°F
Recycle Slurry Separator operation	Replaced the original separator with a new type separator

4.0 EFFECTS OF SDA POLISHING SCRUBBER OPERATION ON EMISSIONS

4.1 Review of Operating and Emissions Data

A review of Unit 2 CFB and SDA operating data before and after a recent SDA off-line event is presented in Appendix A. Therefore, the data represent operation with the SDA on-line. The data covers the period February 1, 2008 through April 24, 2008. These data are provided as examples of typical CFB and SDA operation.

Additional operating and emissions data are presented in Appendix B. The time period March 11, 2008 through March 15, 2008, represents typical unit operation when the SDA was offline, and shows the interaction among boiler limestone flow, SDA slurry flow, and SO_2 emissions. The time period February 27 through March 1, 2008 represents typical unit operation when the boiler limestone feed was reduced, and the SDA slurring feed was increased, and shows that the SO_2 emissions were maintained.

Historic stack test data for the CFB units are presented in Appendix C. Review of all the stack tests reports for NGS demonstrate that the tests at the inlet of the SDA were performed within 90-110 percent of isokinetic. The test ports are located within an acceptable number of diameters upstream and downstream of any flow disturbances. In short, the tests met all the requirements of the test methods.

The FDEP has expressed concerns with certain metals emissions at the stack when the SDA is off-line. However, this condition will occur less than 1.7 percent of the time (144 hr/yr) on an annual basis. The likelihood of less than an 80 percent mix of petcoke being burned during these times would be much less than 1.7 percent. In addition, the fabric filter baghouses continue to operate even when the SDAs are off-line. Therefore, the metals emission limits should continue to be met at the stack when the SDAs are off-line. JEA is committed to voluntarily installing continuous mercury emissions monitors on each unit no later than December 31, 2008, and to operate them for at least 12 months. This in itself should eliminate the necessity for additional stack testing of mercury emissions.

4.2 Potential Emissions Due to Unplanned Shutdown/Startup of CFB Units

This section presents, for each unit, an estimate of the potential emissions of each regulated air pollutant that might occur due to the unplanned shutdown and startup of a CFB should maintenance/repair work be needed on an SDA. Also discussed are the length of time the SDA will be off-line while fuel is being fired, and the total length of time it takes to shut the unit down and to re-start the CFB unit.

The cold start sequence for the CFB units is shown in the attached chart (Figure 4-1). As shown, the total startup time is approximately 48 hours for a cold start. During a cold startup, fuel is first fired in the startup burners (natural gas) at hour 4, and continues through hour 16 when solid fuel burning begins. Solid fuel burning continues until full load is reached on the unit at about hour 48.

The units have CEMS for SO_2, NO_x, and CO. In order to estimate emissions[1] from the CFB units due to cold startup, warm startup, and shutdown events, all such actual events occurring during 2007 to 2008 were examined. Each event type was grouped together and actual average hourly SO_2 and NO_x emissions for the event type was determined, as shown in the attached spreadsheet (Table 4-1).

For CO emissions, actual CEMS data for representative startup events were examined, and on this basis the cold startup emissions shown in Table 4-2 were estimated. For pollutants for which CEMS are not used, emissions were estimated based on the actual fuel firing during the cold startup, AP-42 emission factors for natural gas in CFB boilers, stack testing of the units prior to the SDA and at the stack, and operation of the SDA and fabric filter control devices. As shown in the startup sequence, the SDA is not activated until hour 40 of the 48-hour startup period. The fabric filter is always active during startup, since there is no bypass around the fabric filter. The resulting cold startup emissions are shown in Table 4-2.

Warm startup emissions for CO and non-CEMS pollutants were estimated in a similar manner to the cold startup emissions, by reviewing CEMS data and operational records. Warm startups are a

[1] *For startup: The parameters evaluated were fuel type (gas vs. solid fuel) and SO_2, CO, NO_x and heat input. The startup excess emissions is considered at an end point when the unit is burning 100% solid fuel and the heat input-SO_2-NO_x-CO have stabilized to normal operating levels.*
For shutdown: The parameters examined are heat input and unit load. The shutdown excess emissions start when the heat input and load begin to reduce as fuel is consumed with the endpoint determined by the unit megawatts and pollutant emissions at or near zero.

function of CFB boiler bed temperature, and can last as long as 25 hours. As a conservative estimate, the maximum warm startup time was considered in the emissions analysis, as shown in Table 4-3.

Similarly, unit shutdown emissions were estimated and are shown in Table 4-4.

For the scenario of operating the CFB units while the SDA is off-line:

- Normal operations emissions after maintenance was completed for the unit for SO_2 and NO_x were obtained from the CEMS analysis and tables for startup/shutdown emissions. For all other pollutants, normal operations were represented by the average stack tests emission rate (obtained with the SDA operating). Normal operations were assumed to occur for 19 hours prior to taking the SDA off-line for 6 hours, followed by 27 hours of normal operation. See Unit Shutdown scenario below for why these time periods were used.
- Emissions for operation with the SDA off-line were obtained using the same emission factors or lb/hr emission rates as for normal operation for all pollutants except Pb and Hg. For these two pollutants, it was assumed that emissions were at the permit limit but not exceeding permit limit (worst-case scenario). This is because we believe that only these two pollutants may increase with the SDA off-line, because the boiler limestone feed is increased to compensate for the SDA being off-line. It should be noted, the fabric filter is always active since there is no bypass around it.

For the scenario of the unit shutting down in order to conduct the SDA repair/maintenance:

- The average SDA maintenance time of 6 hours was assumed for SDA off-line. Under this scenario, the entire Unit is shutdown due to malfunctions or to allow the repairs/maintenance.
- Analysis of JEA's shutdown events for Units 1 and 2 for the last 2 years showed the average time to shutdown was 19 hours.
- Analysis of JEA's cold startup events for Units 1 and 2 for the last 2 years showed the average time to startup was 27 hours.
- Normal unit startup emissions for the unit for SO_2 and NO_x were obtained from the CEMS analysis and tables for startup/shutdown emissions. For all other pollutants, startup emissions were estimated using standard JEA startup sequence of events, the same emission factors as for the above scenario, considering whether the SDA is operating or shutdown, and considering the heat input to the unit.
- Normal unit shutdown emissions for the unit for SO_2 and NO_x were obtained from the CEMS analysis and tables for startup/shutdown emissions. For all other pollutants, shutdown emissions were estimated using standard JEA shutdown sequence of events, the same emission factors as for the above

scenario, considering whether the SDA is operating or shutdown, and considering the heat input to the unit.

A comparison of operating one unit while the SDA is down for malfunctions and repairs/maintenance versus taking the unit down to perform the SDA repairs/maintenance is presented in Table 4-5. The total change in emissions per maintenance event for one unit is **168,278 lbs with the CFB shutdown, versus 32,782 lbs with the CFB continuing to operate for SDA repair, a difference of 135,496 lbs per unit. Assuming a total of 20 startups/shutdowns per unit per year due to SDA repair/maintenance, the total potential increase in emissions is 2,710 tons per year total for both units. This analysis confirms that in order to minimize potential emissions increases, it is appropriate and even a requirement based on the condition mandating that emissions be minimized, to allow limited operation of the CFBs with the SDA out of service to affect repairs/maintenance, rather than to initiate unit shutdown/startup procedures.**

An estimate was determined of the potential emissions increase that might be associated with substitute power generation during the time the CFB would be shut down for SDA maintenance/repair, again for all regulated air pollutants. JEA has identified that the most likely source of substitute power generation this summer to be 150 MW from Kennedy Unit 7 combustion turbine and 150 MW from NGS combustion turbines.

- Emissions due to alternative energy generation were developed using JEA Kennedy and Northside gas turbine peaking units (See Table 4-6). Actual pollutant emission rates from these units were developed from Annual Operating Report (AOR) data submitted to the FDEP, which included annual pollutant emission rates and fuel usage, and these were converted to lb/MW emissions.
- These factors were then applied to the total lost generation for this scenario, which is estimated at 275 MW for 144 hr/yr per unit.
- Total additional emissions generated due to NGS CFB shutdown, for various combinations of alternative generation sources, based on 144 hr/yr of SDA downtime for two units total, are shown in Table 4-7. As shown, the maximum additional emissions for alternative power generation are estimated at 18.5 tons CO, 347.8 tons NO_x, 6.5 tons PM, and 110.8 tons SO_2.

TABLE 4-1
NS1 STARTUP-SHUTDOWN EMISSIONS SUMMARY 2007-2008

	Activity 2007	Starting Date	Starting Time	Ending Date	Ending Time	Duration Hours	SO_2 tons	SO_2 Avg lb/hr	Excess SO_2 Tons	lb/MMbtu NO_x rate	(estimate only) NO_x Tons	NO_x Avg lb/hr	Excess NO_x Tons	MMBtu Heat Input	Comments on startup/shutdown status
NS1	Cold start	4/26/2007	0000	4/26/2007	1800	18	0.1	11.1		0.022	0.22	24.4		19961	Cold start after outage- aborted
NS1	Cold start	12/2/2007	1100	12/3/2007	0900	22	2.9	263.6		0.134	1.86	169.0		27741	Cold start after outage
NS1	Cold Start	3/26/2008	2200	3/27/2008	0200	4	0.0	0.0		0.029	0.1	50.0		4572	Aborted
NS1	Cold Startup	5/16/2008	1600	5/17/2008	2000	28	6.0	428.6	1.5	0.106	1.7	121.4		33321	
NS2	Cold Start	5/7/2007	0500	5/8/2007	2000	39	7.2	369.2	2.7	0.167	5.34	274.1	2.59	64006	
NS2	Cold Start	7/23/2007	0600	7/25/2007	1200	54	32.8	1214.8	28.3	0.111	4.42	163.6	1.67	79605	Cold start after outage
NS2	Cold Start	11/14/2007	0100	11/15/2007	1500	38	6.3	331.6	1.8	0.122	2.38	125.1		38968	Cold start after outage
NS2	Cold startup	1/29/2008	1000	1/30/2008	0400	17	18.1	2129.4	13.6	0.06	0.7	82.4		22372	
NS2	Cold startup	4/18/2008	0100	4/19/2008	0400	27	1.8	133.3		0.12	1.8	133.3		36659	Cold start after outage
							avg =	542.4			avg =	127.0			
NS1	Shutdown	3/26/2007	0000	3/26/2007	0700	7	1.2	342.9		0.046	0.35	100.4		15280	On line since 26-Oct-2006, shutdown for outage
NS1	Shutdown	8/31/2007	1900	8/31/2007	2200	3	0.7	466.7		0.033	0.09	62.5		5684	
NS1	Shutdown	11/13/2007	0100	11/14/2007	1500	38	18.2	957.9	13.7	0.15	3.01	158.4	0.26	40116	
NS1	Shutdown	11/22/2007	2000	11/23/2007	0000	4	1.2	600.0		0.044	0.15	73.2		6651	
NS1	Shutdown	2/22/2008	2200	2/23/2008	0000	2	0.6	600.0		0.098	0.1	100.0		4160	
NS1	Shutdown	3/17/2008	0500	3/17/2008	2000	15	1.6	213.3		0.071	0.8	106.7		21069	Significant load reduction for more than one week prior to shutdown
NS1	Restart	3/27/2008	1000	3/28/2008	2300	37	2.0	108.1		0.084	2.4	129.7		63578	
NS1	Shutdown	5/3/2008	1900	5/3/2008	2300	4	8.7	4350.0	4.2	0.075	0.3	150.0		8480	
NS2	Shutdown	1/12/2007	0700	1/12/2007	1200	5	1.2	480.0		0.044	0.35	138.6		15748	
NS2	Shutdown	2/10/2007	1700	2/11/2007	0200	9	1.4	311.1		0.056	0.58	127.8		20543	
NS2	Shutdown	2/18/2007	1300	2/18/2007	2100	8	1.5	375.0		0.051	0.55	137.2		21524	
NS2	Shutdown	4/29/2007	2000	4/30/2007	0200	6	0.7	233.3		0.093	0.63	210.4		13576	
NS2	Shutdown	5/25/2007	0000	5/25/2007	0900	9	1.4	311.1		0.05	0.53	117.1		21075	
NS2	Shutdown	6/1/2007	2200	6/2/2007	0300	5	2.5	1000.0		0.057	0.31	122.2		10721	
NS2	Shutdown	7/1/2007	0700	7/1/2007	2300	16	23.1	2887.5	18.6	0.274	2.92	365.1	0.17	21320	Shutdown for outage
NS2	Shutdown	8/13/2007	1000	8/13/2007	1300	3	0.5	333.3		0.054	0.21	140.0		7775	
NS2	Shutdown	10/21/2007	1900	10/22/2007	0000	5	0.7	280.0		0.049	0.24	97.7		9969	
NS2	Shutdown	11/18/2007	2200	11/19/2007	0200	4	0.8	400.0		0.044	0.23	115.7		10522	
NS2	Shutdown	1/25/2008	2300	1/26/2008	1000	11	4.6	836.4	0.1	0.052	0.3	54.5		13260	
NS2	Shutdown	2/16/2008	1900	2/16/2008	2300	4	0.8	400.0		0.08	0.3	150.0		8641	
NS2	Shutdown	3/28/2008	2300	3/29/2008	0200	3	0.1	66.7		0.086	0.2	133.3		3911	
							avg =	740.6			avg =	132.9			
NS1	Warm Startup	4/27/2007	2000	4/28/2007	2300	26	0.5	38.5		0.228	3.21	247.0	0.46	28169	Warm start after aborted start
NS1	Warm Startup	9/1/2007	1400	9/2/2007	0800	18	11.2	1244.4	6.7	0.07	0.79	87.5		22495	
NS1	Warm startup	11/15/2007	0900	11/16/2007	0400	19	4.2	442.1		0.075	1.15	121.3		30718	
NS1	Warm Startup	11/17/2007	1500	11/18/2007	0100	10	1.9	380.0		0.07	0.60	120.1		17157	
NS1	Hot startup	2/23/2008	1600	2/24/2008	1200	20	22.1	2210.0	17.6	0.074	0.9	90.0		27127	
NS2	Hot restart	1/12/2007	1900	1/13/2007	1000	15	3.7	493.3		0.055	0.70	93.6		25515	
NS2	Hot restart	6/2/2007	1200	6/3/2007	0400	16	8.4	1050.0	3.9	0.069	1.10	137.6		31902	
NS2	Hot restart	2/17/2008	1500	2/18/2008	0600	15	5.4	720.0	0.9	0.064	0.6	80.0		19081	
NS2	Hot startup	5/26/2007	0300	5/26/2007	2000	17	6.4	752.9	1.9	0.067	0.99	116.1		29464	
NS2	Warm startup	2/12/2007	1900	2/13/2007	2000	25	2.0	160.0		0.057	0.57	45.4		19903	
NS2	Warm startup	2/20/2007	1200	2/20/2007	2200	10	0.0	0.0		0.036	0.16	31.6		8784	aborted startup
NS2	Warm startup	8/14/2007	0200	8/15/2007	0500	27	3.0	222.2		0.065	1.41	104.5		43404	
NS2	Warm startup	11/20/2007	2300	11/21/2007	1200	13	0.7	107.7		0.061	0.42	64.4		13719	
NS2	Warm startup	2/21/2007	0000	2/22/2007	0500	29	11.5	793.1	7.0	0.06	1.19	82.2		39708	
							avg =	615.3			avg =	101.5			

Highlighted values exceeded the average daily emissions

Average Daily Emissions

Parameter	Value	Units
SO_2 (mass)	4.5	tons
CO_2 (mass)	7,161	tons
NO_x (rate)	0.081	#/MMBtu
NO_x (mass)	2.75	tons
Heat Input	67,685.43	MMBtu
Operating Time	24	hours
# of Hours in which Operation occurred	24	[count]

TABLE 4-2

ESTIMATED COLD START-UP EMISSIONS

			Total Emissions					
Activity	Time Start (hour)	Duration (hours)	CO [a] (lb)	SAM [b] (lb)	Fluoride [b] (lb)	VOC [b] (lb)	Lead [b] (lb)	Mercury [b] (lb)
Activities prior to fuel burning	0	11	--	--	--	--	--	--
Fire Startup Burners	4	12	274	--	--	1.65	9.25E-02	3.99E-02
Turbine Pre-Warm	4	4	--	--	--	--	--	--
Refractory Cure	5	12	--	--	--	--	--	--
Build Bed Temp to 1,100 deg., Start Solid Fuel	17	10	20,048	0.52	0.31	2.89	1.63E-01	7.01E-02
Build Bed Temp to 1,400 deg., Build Boiler Press	27	4	12,252	0.22	0.13	1.23	6.90E-02	2.97E-02
Roll Turbine	15	3	--	--	--	--	--	--
Unit Online - Breaker Closed	18	0	--	--	--	--	--	--
Hold at 25% MW Loading	18	3	--	--	--	--	--	--
Unit Offline - Perform Overspeed Trip Test	21	1	--	--	--	--	--	--
2nd Roll up of Turbine After O/S Tests	22	1	--	--	--	--	--	--
Ramp to Full Load	23	25	34,663	1.91	1.15	10.63	2.89E-01	1.10E-01
Place Spray Dryer Absorber In Service	40	4						
Online At Full Load	48	0.5	83	0.13	0.08	0.73	7.01E-03	1.42E-03
Total (tons)			**33.66**	**0.0014**	**0.00084**	**0.0086**	**3.10E-04**	**1.25E-04**

[a] Emission data from CEMS for solid fuel and AP-42 Section 1.4 for Natural Gas Combustion

[b] Emission data from historical stack testing for solid fuel and AP-42 Section 1.4 for Natural Gas Combustion

SDA Offline		
SAM	8.10E-05	average 2002 stack test value assuming 98 % load
Fluoride	4.87E-05	average 2002 and 2004 stack test value assuming 98 % load
VOC	4.50E-04	average 2002 stack test value assuming 98 % load
Lead	2.53E-05	Permit limit
Mercury	1.09E-05	Permit limit

SDA Online		
SAM	8.10E-05	average 2002 stack test value assuming 98 % load
Fluoride	4.87E-05	average 2002 and 2004 stack test value assuming 98 % load
VOC	4.50E-04	average 2002 stack test value assuming 98 % load
Lead	4.32E-06	average 2002 and 2004 stack test value assuming 98 % load
Mercury	8.77E-07	average 2002 and 2004 stack test value assuming 98 % load

AP-42 Emission Factors Natural Gas (lb/MMBtu)	
SAM	None
Fluoride	None
VOC	0.0055
Lead	5.00E-07
Mercury	2.60E-07
CO	0.084

TABLE 4-3
ESTIMATED WARM START-UP EMISSIONS

	Total Emissions					
	CO [a]	SAM [b]	Fluoride [b]	VOC [b]	Lead	Mercury
Hour	(lb)	(lb)	(lb)	(lb)	(lb)	(lb)
1	16.09	2.11E-03	1.27E-03	0.0117	6.58E-04	2.83E-04
2	333.54	1.19E-02	7.16E-03	0.06615	3.72E-03	1.60E-03
3	457.57	1.53E-02	9.20E-03	0.08505	4.78E-03	2.06E-03
4	696.16	1.85E-02	1.12E-02	0.10305	5.79E-03	2.50E-03
5	867.41	2.06E-02	1.24E-02	0.1143	6.43E-03	2.77E-03
6	1018.58	2.28E-02	1.37E-02	0.1269	7.13E-03	3.07E-03
7	1340.34	2.71E-02	1.63E-02	0.1503	8.45E-03	3.64E-03
8	1598.38	3.05E-02	1.83E-02	0.1692	9.51E-03	4.10E-03
9	1425.88	3.48E-02	2.09E-02	0.1935	1.09E-02	4.69E-03
10	1880.17	4.59E-02	2.76E-02	0.25515	1.43E-02	6.18E-03
11	2274.78	5.56E-02	3.34E-02	0.3087	1.74E-02	7.48E-03
12	3440.26	6.03E-02	3.62E-02	0.3348	1.88E-02	8.11E-03
13	3126.40	7.02E-02	4.22E-02	0.39015	2.19E-02	9.45E-03
14	1265.88	8.30E-02	4.99E-02	0.46125	2.59E-02	1.12E-02
15	1297.66	8.72E-02	5.24E-02	0.4842	2.72E-02	1.17E-02
16	1682.77	8.85E-02	5.32E-02	0.4914	2.76E-02	1.19E-02
17	1122.43	9.59E-02	5.77E-02	0.5328	3.00E-02	1.29E-02
18	75.66	1.25E-01	7.52E-02	0.6948	3.91E-02	1.68E-02
19	39.14	1.59E-01	9.53E-02	0.88065	4.95E-02	2.13E-02
20	37.91	1.71E-01	1.03E-01	0.9477	5.33E-02	2.30E-02
21	32.35	1.75E-01	1.05E-01	0.97065	5.46E-02	2.35E-02
22	30.14	1.74E-01	1.05E-01	0.96885	9.30E-03	1.89E-03
23	28.90	1.80E-01	1.08E-01	1.00035	9.60E-03	1.95E-03
24	28.59	1.78E-01	1.07E-01	0.98955	9.50E-03	1.93E-03
25	26.53	1.79E-01	1.08E-01	0.99495	9.55E-03	1.94E-03
Total (tons)	**12.07**	**0.0011**	**0.00063**	**0.0059**	**0.000237**	**9.80E-05**

[a] Emission data from CEMS

[b] Emission data from historical stack testing

SDA Online	lb/MMBtu	
SAM	8.10E-05	average 2002 stack test value assuming 98 % load
Fluoride	4.87E-05	average 2002 and 2004 stack test value assuming 98 % load
VOC	4.50E-04	average 2002 stack test value assuming 98 % load
Lead	4.32E-06	average 2002 and 2004 stack test value assuming 98 % load
Mercury	8.77E-07	average 2002 and 2004 stack test value assuming 98 % load

SDA Offline		
SAM	8.10E-05	average 2002 stack test value assuming 98 % load
Fluoride	4.87E-05	average 2002 and 2004 stack test value assuming 98 % load
VOC	4.50E-04	average 2002 stack test value assuming 98 % load
Lead	2.53E-05	Permit limit
Mercury	1.09E-05	Permit limit

TABLE 4-4
ESTIMATED SHUT-DOWN EMISSIONS

Activity	Time Start (hour)	Duration (hours)	Total Emissions CO [a] (lb)	SAM [b] (lb)	Fluoride [b] (lb)	VOC [b] (lb)	Lead (lb)	Mercury (lb)
Begin reducing AQCS slurry density	0	24	23,968	1.11	0.67	6.19	0.35	0.15
Begin reducing load	24	5	1,517	0.12	0.07	0.67	0.02	0.01
SDA out of service at 240°F inlet or 75 MW	26	0.25						
Clear and drain AQCS tanks	26.25	6						
Run fuel off of solid fuel feeder belts	26	3						
Verify all economizer crushers running	24	0.5						
Place above bed burners in service	26	3						
Remove unit from service (off-line)	29	0.25						
Hang crossover clearance	29.25	1						
Relieve boiler pressure using HP/LP bypass system	29	4						
Close boiler stop valve at 100 psi	33	0.1						
Open all vents and drains at 25 psi	33	2						
Open top 4 floor HRA doors	29	1						
Take furnace draft to -0.5 in.	30	0.5						
Increase total air flow to 2000 klbs/hr	30.5	0.25						
Maintain PA duct pressure 65 - 70 in.	30.5	4						
Strip bed from boiler	24	15						
Flush INTREX sections	29	11						
Crack open cycone crossover inlet doors at <300 °F	37	0.5						
Begin exterior crossover cleaning	38	12						
Blasting in back pass area begins	37	13						
Remove fans from service at <120 °F	50	0.5						
Open remaining backpass doors	50.5	1						
Adjust furnace draft to 0.5 in. using 1 ID fan	51.5	0.5						
Place locking device on ID fan in service	52	0.5						
Hang boiler and stripper cooler clearances	52	2						
Begin internal crossover cleaning	54	12						
Shut down blowers when LOS achieved on INTREX's	66	0.25						
Stop stripper cooler rotary valves	40	0.1						
Place second gathering conveyor in service	40	1						
Place second bed ash blower in service	40	1						
Shut down bed ash blowers when surge hoppers empty	41	0.25						
Total (tons)			**12.74**	**0.00062**	**0.00037**	**0.00343**	**1.82E-04**	**7.77E-05**

[a] Emission data from CEMS

[b] Emission data from historical stack testing

SDA Online		
SAM	8.10E-05	average 2002 stack test value assuming 98 % load
Fluoride	4.87E-05	average 2002 and 2004 stack test value assuming 98 % load
VOC	4.50E-04	average 2002 stack test value assuming 98 % load
Lead	4.32E-06	average 2002 and 2004 stack test value assuming 98 % load
Mercury	8.77E-07	average 2002 and 2004 stack test value assuming 98 % load

SDA Offline		
SAM	8.10E-05	average 2002 stack test value assuming 98 % load
Fluoride	4.87E-05	average 2002 and 2004 stack test value assuming 98 % load
VOC	4.50E-04	average 2002 stack test value assuming 98 % load
Lead	2.53E-05	Permit limit
Mercury	1.09E-05	Permit limit

TABLE 4-5
COMPARISON OF EMISSIONS WITH/WITHOUT UNIT SHUTDOWN DURING SDA MAINTENANCE - ONE UNIT

	SDA Maintenance with Unit Operating and SDA Off-Line				SDA Maintenance with Unit Shutdown				
Pollutant	Normal Unit Operation 19 hrs (lbs)	Unit Operation w/SDA Off-Line 6 hrs (lbs)	Normal Unit Operation 27 hrs (lbs)	Total Emissions (lbs)	Normal Unit Shutdown 19 hrs (lbs)	Unit Off-Line for SDA Maintenance 6 hrs (lbs)	Normal Unit Cold Startup 27 hrs (lbs)	Alternative Energy Generation[a] (lbs)	Total Emissions (lbs)
SO_2	7,125	2,250	10,125	19,500	14,079	0	14,634	3,620	32,333
PM	209	66	297	572		0		1,437	1,437
NO_x	4,351	1,374	6,183	11,908	2,527	0	3,429	26,617	32,573
CO	262.2	82.8	372.6	718	25,480	0	67,320	9,077	101,877
VOC	23.56	7.44	33.48	64	6.86	0	17.2	49	73
SAM	4.18	1.32	5.94	11	1.2	0	2.8		4.0
HF	2.47	0.78	3.51	6.8	0.74	0	1.68		2.4
Pb	0.23	0.42	0.32	1.0	0.37	0	0.62	1.7	2.7
Hg	0.05	0.18	0.06	0.29	0.155	0	0.25		0.41
			Total =	32,782				Total =	168,302

Normal operation:
SO_2- 4.5 tons/day = 375 lb/hr
PM- 0.004 lb/MMBtu; 11 lb/hr
NO_x - 2.75 tons/day = 229 lb/hr
CO- 0.005 lb/MMBtu; 13.8 lb/hr
VOC- 4.5E-04 lb/MMBtu; 1.24 lb/hr
SAM- 8.1E-05 lb/MMBtu; 0.22 lb/hr
HF- 4.87E-05 lb/MMBtu; 0.13 lb/hr
Pb- 4.32E-06 lb/MMBtu; 0.012 lb/hr
Hg- 8.77E-07 lb/MMBtu; 0.0024 lb/hr
SDA Off-Line:
All pollutant emission factors remain the same, except for:
Pb- 2.53E-05 lb/MMBtu; 0.07 lb/hr (permit limit)
Hg- 1.09E-05 lb/MMBtu; 0.03 lb/hr (permit limit)

[a]Assumes 75% of 275 MW-hrs lost for 19 hours plus 27 hours, and 100% of 275 MW lost for 6 hours.
Total MW-hrs lost = 11,137 MW

Normal Unit Shutdown:
SO_2- 741 lb/hr
PM- 0.004 lb/MMBtu; 11 lb/hr
NO_x - 133 lb/hr
CO- 0.005 lb/MMBtu; 13.8 lb/hr
VOC- 4.5E-04 lb/MMBtu; 1.24 lb/hr
SAM- 8.1E-05 lb/MMBtu; 0.22 lb/hr
HF- 4.87E-05 lb/MMBtu; 0.13 lb/hr
Pb- 4.32E-06 lb/MMBtu; 0.012 lb/hr
Hg- 8.77E-07 lb/MMBtu; 0.0024 lb/hr

Normal Unit Startup:
SO_2- 542 lb/hr
PM- 0.004 lb/MMBtu; 11 lb/hr
NO_x - 127 lb/hr
CO- 0.005 lb/MMBtu; 13.8 lb/hr
VOC- 4.5E-04 lb/MMBtu; 1.24 lb/hr
SAM- 8.1E-05 lb/MMBtu; 0.22 lb/hr
HF- 4.87E-05 lb/MMBtu; 0.13 lb/hr
Pb- 4.32E-06 lb/MMBtu; 0.012 lb/hr
Hg- 8.77E-07 lb/MMBtu; 0.0024 lb/hr

TABLE 4-6
EMISSIONS FROM ALTERNATE ELECTRICAL GENERATION SOURCES

Unit	Fuel	Maximum Generation [a] (MW)	Maximum Heat Input [a] (MMBtu/hr)	MMBtu/MW	Emission Rate (lb/MMBtu) [b] CO	NO_x	PM	PM_{10}	SO_2	Lead	VOC	Emission Rate per MW CO (lb/MW)	NO_x (lb/MW)	PM (lb/MW)	PM_{10} (lb/MW)	SO_2 (lb/MW)	Lead (lb/MW)	VOC (lb/MW)
Kennedy Unit No. 7	Distillate Oil	170	1822.0	10.72	0.076	0.223	0.012	0.0043	0.0303	1.40E-05	4.10E-04	0.815	2.390	0.129	0.046	0.325	1.50E-04	0.00439
	Natural Gas	170	1623.0	9.55	0.0284	0.046	0.0066	1.90E-03	0	0	0.0021	0.271	0.439	0.063	0.018	0.0000	0.00E+00	0.02005
Northside Unit No. 3	Distillate Oil	56.2	901	16.03	0.0033	0.88	0.012	0.012	0.303	1.40E-05	4.10E-04	0.053	14.108	0.192	0.192	4.858	2.24E-04	0.00657
Northside Unit No. 4	Distillate Oil	56.2	901	16.03	0.0033	0.88	0.012	0.012	0.303	1.40E-05	4.10E-04	0.053	14.108	0.192	0.192	4.858	2.24E-04	0.00657
Northside Unit No. 5	Distillate Oil	56.2	901	16.03	0.0033	0.88	0.012	0.012	0.303	1.40E-05	4.10E-04	0.053	14.108	0.192	0.192	4.858	2.24E-04	0.00657
Northside Unit No. 6	Distillate Oil	56.2	901	16.03	0.0033	0.88	0.012	0.012	0.303	1.40E-05	4.10E-04	0.053	14.108	0.192	0.192	4.858	2.24E-04	0.00657

[a] Data from Air Operation Permit Nos. 0310045-016AV and 0310047-016-AV.

[b] Data Calculated from 2007 AOR submission.

TABLE 4-7
EMISSIONS DUE TO ALTERNATIVE ENERGY GENERATION- JEA SYSTEM

Facility	Total Generation (MW)	Duration[a] (hour)	CO (ton)	NO_x (ton)	PM (ton)	PM_{10} (ton)	SO_2 (ton)	Lead (ton)	VOC (ton)
Kennedy Unit No. 7, Distillate Oil	125	288	14.7	43.0	2.32	0.83	5.8	0.0027	0.08
Northside Unit Nos. 3, 4, 5, 6	150	288	1.1	304.7	4.16	4.16	104.9	0.0048	0.14
Total	**275**		**15.8**	**347.8**	**6.47**	**4.99**	**110.8**	**0.0075**	**0.22**

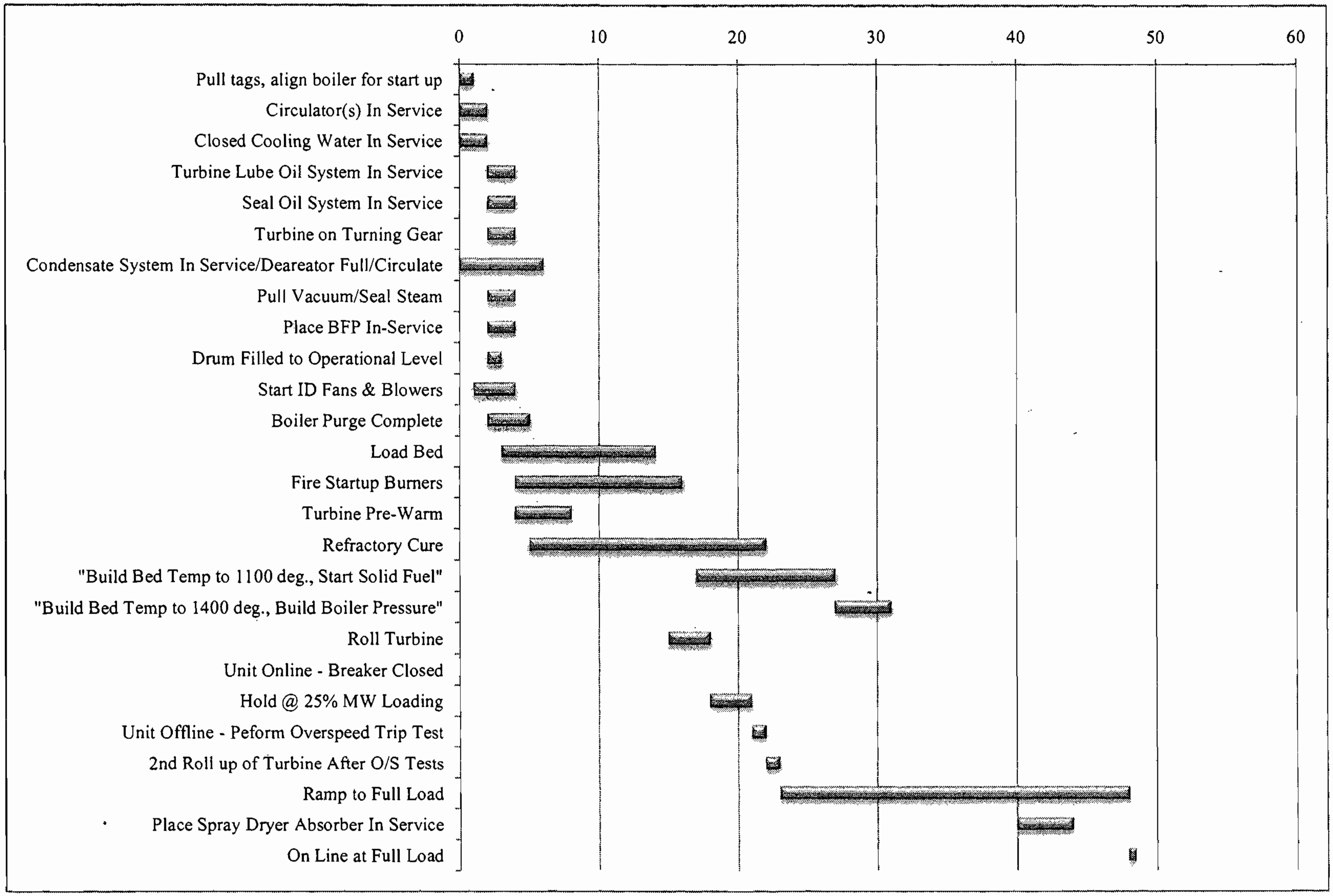
Facility	Total Generation (MW)	Duration (hour)	CO (ton)	NO_x (ton)	PM (ton)	PM_{10} (ton)	SO_2 (ton)	Lead (ton)	VOC (ton)
Kennedy Unit No. 7, Distillate Oil	150	288	17.6	51.6	2.78	1.00	7.0	0.0032	0.09
Northside Unit Nos. 3, 4, 5, 6	125	288	1.0	253.9	3.46	3.46	87.4	0.0040	0.12
Total	**275**		**18.5**	**305.6**	**6.24**	**4.46**	**94.5**	**0.0073**	**0.21**

Facility	Total Generation (MW)	Duration (hour)	CO (ton)	NO_x (ton)	PM (ton)	PM_{10} (ton)	SO_2 (ton)	Lead (ton)	VOC (ton)
Kennedy Unit No. 7, Natural Gas	125	288	4.9	7.9	1.13	0.33	0.0	0.0000	0.36
Northside Unit Nos. 3, 4, 5, 6	150	288	1.1	304.7	4.16	4.16	104.9	0.0048	0.14
Total	**275**		**6.0**	**312.6**	**5.29**	**4.48**	**104.9**	**0.0048**	**0.50**

Facility	Total Generation (MW)	Duration (hour)	CO (ton)	NO_x (ton)	PM (ton)	PM_{10} (ton)	SO_2 (ton)	Lead (ton)	VOC (ton)
Kennedy Unit No. 7, Natural Gas	150	288	5.9	9.5	1.36	0.39	0.0	0.0000	0.43
Northside Unit Nos. 3, 4, 5, 6	125	288	1.0	253.9	3.46	3.46	87.4	0.0040	0.12
Total	**275**		**6.8**	**263.4**	**4.82**	**3.85**	**87.4**	**0.0040**	**0.55**

[a] Two CFB units at 144 hr/yr each downtime.

FIGURE 4-1
COLD STARTUP SEQUENCE FOR NGS CFB UNITS



5.0 REQUESTED REVISIONS TO TITLE V PERMIT

JEA's position is that the SDA polishing scrubber must be operated only as needed to meet the sulfur dioxide and sulfuric acid mist limits; additional limestone added to the CFBs allows JEA to avoid use of the polishing scrubber. In addition, consistent with Condition H.23 of the Title V permit, the SDA polishing scrubbers should be repaired and maintained while the CFBs remain operational to the extent possible, consistent with good air pollution control practices for minimizing emissions. Because of concerns raised by FDEP and Jacksonville EQD, a permit clarification is warranted.

Requested Relief

A. Malfunctions

1. Under the current permit, if the SDA polishing scrubbers malfunction, the permittee may take the scrubber off-line for up to 2 hours in a 24-hour period, regardless of excess emissions and regardless of the circumvention provisions, while the CFBs continue to operate.

2. JEA requests a clarifying comment or condition in the permit that if the SDA polishing scrubbers experience a malfunction and there are no excess emissions of sulfur dioxide (SO_2) based on the CEMS data, the polishing scrubber may be taken off-line until the malfunction has been corrected, while the CFBs continue to operate (not limited to 2 hours in a 24-hour period).

B. Maintenance/Repairs

1. It is JEA's position that the SDA polishing scrubbers may be taken off-line for needed maintenance and repairs while the CFBs remain operational as long as there is no resulting increase in SO_2 emissions, based on CEMS data; the permit condition requires operation of the scrubber as needed to meet the limits.

2. JEA requests immediate relief through an air construction and Title V permit amendment.

3. Draft permit wording is provided below for the Department's review and consideration.

This wording amends Air Permit No. 0310045-003-AC/PSD-FL-265 and Title V Permit No. 0310045-016-AV, for the Northside Generating Station, as follows:

FROM:

H.5. Sulfur Dioxide Control: Sulfur dioxide (SO_2) and acid gases shall be controlled by the injection of limestone into the CFB boiler beds. Residual sulfur dioxide and acid gases shall be further controlled by the use of add-on air quality control systems for Units 1 and 2 to meet limits of 0.2 lb/MMBtu, 24-hr block average, and 0.15 lb/MMBtu, 30-day rolling average.

[Applicant Request; and 0310045-003-AC/PSD-FL-265]

TO:

H.5. Sulfur Dioxide Control: Sulfur dioxide (SO_2) and acid gases shall be controlled by the injection of limestone into the CFB boiler beds. Residual sulfur dioxide and acid gases shall be further controlled by the use of add-on air quality control systems for Units 1 and 2 **as needed** to meet limits of 0.2 lb/MMBtu, 24-hr block average, and 0.15 lb/MMBtu, 30-day rolling average.

[Applicant Request; and 0310045-003-AC/PSD-FL-265]

FROM:

H. 24. Continuous Emissions Monitoring Systems. The permittee shall install, calibrate, operate, and maintain Continuous Emission Monitoring Systems (CEMS) in the stack to measure and record the sulfur dioxide, oxides of nitrogen, carbon monoxide, and visible emissions from CFB Boilers No. 1 and 2. An emission level above a BACT limit, considering the 6-minute, 24-hour and 30-day rolling average periods, as applicable, shall be reported to the ERMD-EQD pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems shall comply with the certification, performance specifications, and quality assurance, and other applicable requirements of 40 CFR Part 75 and 40 CFR Part 60 (Appendix B), as indicated above. Periods of startup, shutdown, and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the limits in Table 1 following the format of 40 CFR 60.7 [As revised, 64 Fed Reg. 7458 (Feb. 12, 1999)].

[Applicant Request; and 0310045-003-AC/PSD-FL-265]

TO:

H. 24. Continuous Emissions Monitoring Systems. The permittee shall install, calibrate, operate, and maintain Continuous Emission Monitoring Systems (CEMS) in the stack to measure and record the sulfur dioxide, oxides of nitrogen, carbon monoxide, **mercury**, and visible emissions from CFB Boilers No. 1 and 2. An emission level above a BACT limit, considering the 6-minute, 24-hour and 30-day rolling average periods, as applicable, shall be reported to the ERMD-EQD pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems shall comply with the certification, performance specifications, and quality assurance, and other applicable requirements of 40 CFR Part 75 and 40 CFR Part 60 (Appendix B), as indicated above. Periods of startup, shutdown, and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the limits in Table 1 following the format of 40 CFR 60.7 [As revised, 64 Fed Reg. 7458 (February 12, 1999)]. **The mercury CEMS shall be installed and operational no later than December 31, 2008, and shall be**

operated for a minimum of twelve (12) months. The mercury CEMS shall be operated in accordance with the manufacturer's specifications.

[Applicant Request; and 0310045-003-AC/PSD-FL-265]

FROM:

H. 57. Circumvention. The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.

TO:

H. 57. Circumvention. The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly, **except that the spray dryer absorbers may be taken offline (no slurry flow) due to malfunctions or to perform repairs and maintenance activities, while the CFBs remain operational up to a total of 144 hours per year, per unit. This shall not be considered "circumvention" because this practice minimizes air pollutant emissions. If the spray dryer absorbers are taken offline for any reason, limestone injection to the CFBs shall be increased to a level sufficient to ensure that the sulfur dioxide and sulfuric acid mist emission limits are achievable.**

JEA proposes to track SDA downtime to demonstrate compliance with the proposed time limit of 144 hours per year, per unit, in the following manner. The primary SDA parameters to be monitored will be:

- SDA Slurry Flow;
- SDA Inlet Temperature;
- SDA Outlet Temperature; and
- Unit Megawatts.

Using these parameters, JEA can determine Process On/Off conditions, SDA Operation, and Unit Startup/Shutdown. Data from JEA's data historian will used to collect and store this data. While the system collects this data continuously, the examination and aggregation of the SDA data will be included in the JEA's Air Compliance group's daily reporting activities.

APPENDIX A

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL USA 32653
Telephone (352) 336-5600
Fax (352) 336-6603
www.golder.com

May 7, 2008 0838-7595

Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

Attention: Mr. N. Bert Gianazza

RE: AIR ENGINEERING EVALUATION OF UPSET EVENT FOR UNIT NO. 2 AT NORTHSIDE GENERATING STATION

Dear Mr. Gianazza:

Attached is Golder Associates Inc. (Golder) report concerning the upset event associated with the Spray Dryer Absorber (SDA) associated with Unit No. 2 at the Northside Generating Station. The report was generated after conducting the site visit and gathering relevant information on the operation of the Unit and the SDA and focuses on the air quality aspects of the event. If you have any questions concerning this evaluation, please feel free to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/sl

Enclosures

cc: K. Kosky, GAI

L050708_595.doc

EVALUATION OF NORTHSIDE UNIT NO. 2
SPRAY DRYER ABSORBER UPSET EVENT

1.0 INTRODUCTION

On April 6, 2008, the Jacksonville Electric Authority (JEA) Northside Generating Station (NGS) Unit No. 2 experienced an implosion of the Spray Dryer Absorber (SDA) lower vessel hopper. This failure compromised the structural integrity of the hopper to the extent that the unit could not be operated reliably, and therefore the unit was shut down. Due to concerns over structural integrity, safety, and reliability, the entire unit (including SDA) was taken out of service until the extent of damage could be assessed. The unit had just come off of a planned outage. After inspection, it was determined no damage to internals or components had occurred, and only the vessel itself had been damaged.

Structural repairs were then made to the vessel, including installing temporary bracing of the hopper, and air testing of the hopper to confirm hopper stability and serviceability. The Unit was restarted on April 18, 2008.

The purpose of this evaluation was to assess the air pollution aspects of this event and to determine if the unit is now working properly and operating in compliance with the Title V air operation permit (Permit No. 0310045-016-AV). A site visit was conducted on April 24, 2008, to the NGS for the purpose of assessing the situation, gathering data, and discussing with JEA operations staff.

2.0 NORTHSIDE UNIT NO. 2 OPERATION

Northside Unit No. 2 is a coal and petroleum coke (petcoke)-fired circulating fluidized bed (CFB) boiler. The unit is rated at 297.5 megawatts (MW), with a maximum heat input rate of 2,764 million British thermal units per hour (MMBtu/hr). It includes solid fuel delivery and storage facilities, limestone preparation and storage facilities (including three limestone dryers), a lime silo, aqueous ammonia storage, polishing scrubber (the SDA), baghouse, and ash removal and storage facilities.

The NGS CFB boiler operates on the principle of combusting fuel on a fluidized bed of material. For Unit No. 2, coal or petcoke is burned within a bed of hot incombustible particles (limestone/fly ash). The particles are suspended by the upward flow of the fluidizing gas (combustion air/products of combustion) within the combustor. The coal/petcoke is ground to the appropriate particle size prior to being introduced into the CFB boiler, and therefore also burns in suspension. Due to high velocities in the CFB boiler, a portion of the limestone/fly ash is continually carried over from the bed (approximately 20 percent). Most of this material is collected in the downstream baghouse and is then recirculated back to the CFB boiler. However, a portion of this material is bled off while fresh limestone is continually added to make up the difference.

The NGS CFB boiler is equipped with a selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide (NO_x) emissions, limestone injection to reduce sulfur dioxide (SO_2) emissions and other acid gases, fabric filter to reduce particulate matter (PM) and particulate matter less than 10 microns (PM_{10}) emissions, while maximizing combustion efficiency to limit carbon monoxide (CO) and volatile organic compound (VOC) emissions, and minimizing NO_x formation. A flow diagram of the air quality control system downstream of Unit No. 2 is shown in Figure 1.

The use of limestone as the bed material in the CFB boiler acts to inherently control acid gas emissions, such as SO_2, hydrogen chloride (HCl), and hydrogen fluoride (HF). The SO_2 reacts with the calcined lime to form calcium sulfate, which is caught in the downstream baghouse. The downstream SDA also provides additional acid gas scrubbing. Recycled ash from the baghouse and water are mixed to a slurry, which is then sprayed into the SDA. The SO_2 reacts with the slurry to form calcium sulfite or calcium sulfate, which is also captured in the downstream baghouse. The other acid gases are captured in a similar manner.

This combination of CFB boiler and SDA allows JEA to vary the limestone injection rate into the CFB and recycled ash slurry injection into the SDA in order to control SO_2 emissions to meet permit limits. At times when limestone injection into the CFB must be limited, the slurry feed to the SDA can be increased to achieve equivalent acid gas reduction. Limestone and slurry feed rates are also related to the sulfur content of the fuels being burned (coal and/or petcoke). Northside Unit No. 2 currently burns about 90 percent petcoke and 10 percent coal on a heat input basis.

The design of the CFB boiler allows operation over a large load range even though Unit No. 2 is a base loaded unit. The CFB boiler vendor (Foster Wheeler USA) has guaranteed emissions down to 50-percent load, and based upon initial demonstrations, operation at loads as low as 25 percent are achievable while still meeting performance and emission requirements.

Emission limits for Unit No. 2 are summarized in Table 1.

TABLE 1: EMISSION LIMITS FOR CFB UNIT NO. 2

Pollutant	**Emission Limits – Per Unit**
Visible emissions	10 percent opacity, 6-minute block average
SO_2	0.2 lb/MMBtu, 24-hour block average 0.15 lb/MMBtu, 30-day rolling average
NO_x	0.09 lb/MMBtu, 30-day rolling average
PM/PM_{10}	0.011 lb/MMBtu, 3-hour average
CO	350 lb/hr, 24-hour block average
VOCs	14 lb/hr, 3-hour average
Lead (Pb)	0.07 lb/hr, 3-hour average
Sulfuric Acid Mist (H_2SO_4)	1.1 lb/hr, 3-hour average
HF	0.43 lb/hr, 3-hour average
Mercury (Hg)	0.03 lb/hr, 6-hour average

Note:
lb/MMBtu = pounds per million British thermal units.
lb/hr = pounds per hour.

SO_2, NO_x, and CO are measured continuously by continuous emissions monitoring systems (CEMS). Opacity is also measured continuously by a continuous opacity monitoring system (COMS). Annual compliance testing is required for PM/PM_{10} emissions. Initial stack testing was conducted for VOC, Pb, H_2SO_4, HF, and Hg.

3.0 SPRAY DRYER ABSORBER OPERATION

The SDA is referred to as a "polishing scrubber" because the primary removal of acid gases from Unit No. 2 is in the CFB itself (see above description). At the top of the SDA vessel, the hot flue gases, which contain limestone/fly ash carryover from the CFB, enter the vessel. A slurry is also introduced at the top of the vessel by spray nozzles. The slurry and flue gases mix, causing the water in the slurry to evaporate. Most of the remaining solids become suspended in the gas flow, and exit the SDA along with the flue gases, to be captured in the downstream baghouse.

The SDA contains a lower vessel hopper, which is a cone shaped hopper located on the bottom of the SDA vessel. This hopper acts to collect particles that fall out of the flue gas flow stream prior to the gases exiting the SDA vessel. This is the portion of the SDA that was damaged from the implosion on April 6.

A further description of the SDA and its operation, as contained in JEA's standard operating procedures, is shown in Attachment A.

The SDA is designed for an outlet flue gas temperature of 165 to 175 degrees Fahrenheit (°F), in order to ensure evaporation of the moisture in the slurry. Automatic controls reduce the slurry feed rate as necessary to maintain the outlet temperature above 155°F.

4.0 VISUAL OBSERVATION

GolderAssociates Inc. (Golder) personnel (David A. Buff, P.E.) conducted a visual observation of the damaged portion of the SDA on April 21, 2008. Unit No. 2 was operating normally at the time (unit was brought back online on April 18, following the event). The SDA outer covering over the lower vessel hopper had been removed previously, subsequent to the implosion event, in order for JEA personnel to inspect the hopper and make structural repairs. The visual observation confirmed an implosion, but no other visible signs of abnormal operation were seen. No gas leaks, vibration, or abnormal noises associated with the SDA were detected.

5.0 REVIEW OF OPERATING DATA

In order to evaluate the operation of Unit No. 2 and specifically the operation of the SDA, both before and after the implosion event, Unit No. 2 operating data was reviewed. The plant monitors a number of parameters related to the operation of the unit and the SDA. Several of the more pertinent parameters were analyzed to determine if a change in operation post-event had occurred.

Shown in Figure 2 are hourly averages of Unit No. 2 operating data consisting of gross MW production, boiler limestone flow (1,000 lb/hr), SO_2 concentration [parts per million (ppm)] at the stack, and SDA slurry feed rate [gallons per minute (gpm)]. The time period is February 1, 2008 through March 30, 2008 (pre-event data) and April 19, 2008 through April 27, 2008 (post-event data).

Note that startup and shutdown hours were excluded from the analysis, as it was the intent of this analysis to evaluate normal operation of the unit.

As shown in Figure 2, Unit No. 2 power generation was high during the post-event period, ranging from about 250 to 315 MW. This level of power generation is as high as, or higher, than that experienced during the pre-event period, clearly indicating that power generation was not affected by the event.

Unit No. 2 boiler limestone flow during the pre-event period was typically in the range of 50,000 to about 90,000 lb/hr, with some periods of mainly lower flows down to about 25,000 lb/hr. Post-event limestone flow rates were well within this range of operation, ranging from about 40,000 to about 65,000 lb/hr.

Unit No. 2 SDA slurry feed rate during the pre-event period was typically in the range of 100 gpm to about 160 gpm, with some periods of mainly lower flows down to about 60 gpm. SDA slurry feed rate post-event was within the range experienced during the pre-event period, i.e., from about 100 to 160 gpm, with some limited periods up to 175 gpm.

During the pre-event period, SO_2 stack concentrations range from 0 to about 100 ppm, but most 1-hour averages fall within the range of 50 to 75 ppm (see Figure 2). Post-event concentrations fall within the range of 50 to 65 ppm, indicating normal operation of the CFB/SDA system.

SDA flue gas inlet and outlet temperatures are portrayed in Figure 3. As described in the Air Quality Control System (AQCS) Guidelines (Attachment A), the target SDA outlet temperature is 175°F at full load. At reduced loads, the outlet temperature is raised to 185°F. If the density of the slurry feed is less than 10 percent, the SDA outlet temperature can be raised as high as 190°F. As shown in Figure 3, SDA inlet temperatures appear to be somewhat higher during the post-event period compared to pre-event conditions. However, this is a function of CFB operation and not SDA operation.

SDA outlet temperature is a function of the SDA inlet temperature, as well as, SDA operation. The post-event temperatures are well within the pre-event temperature range, with the majority of data complying with the AQCS guideline. However, for the most part, the temperatures are higher than the pre-event temperatures, but still within the AQCS guideline of 175 to 190°F.

Based on the review of the Unit No. 2 operating data before and after the SDA event, no discernible difference is indicated in SDA operation. All systems are indicated to be operating properly and efficiently. Therefore, it is concluded that the boiler and SDA systems were functioning properly. As described previously, both the limestone flow and the SDA slurry feed rate can be varied by plant personnel to achieve the desired level of outlet SO_2 concentration and comply with the unit SO_2 emission limits.

6.0 REVIEW OF CEMS DATA

Data from the CEMS for SO_2, NO_x, and CO were reviewed to assess the variation of these pollutants during the pre- and post-event periods. Hourly SO_2 data from the Unit No. 2 continuous emission monitoring system (CEMS) in both ppm and lb/MMBtu are shown in Figure 4. Also shown are the SO_2 emission limits, which are in terms of lb/MMBtu. As shown, the normal range of operation (pre-event) is in the range of 50 to 70 ppm, with some hourly periods much lower or much higher. Post-event operation is certainly within the pre-event range, with most values in the range of 50 to 70 ppm.

The 24-hour block average emission limit for SO_2 is 0.20 lb/MMBtu, while the 30-day rolling average is 0.15 lb/MMBtu. Pre-event hourly averages were maintained below 0.20 lb/MMBtu for the most part, in order to ensure that both the 24-hour average and the 30-day rolling average limits are met. The post-event SO_2 data follow the same trend.

Hourly values of SO_2 removal efficiency for Unit No. 2 are shown in Figure 5. The removal efficiency is based on monitoring the SO_2 concentration in ppm at the boiler outlet and at the stack (from the CEMS), and is a function of SDA operation. The SO_2 removal efficiency varies widely, but is normally within the range of 40 to 80 percent, as indicated during the pre-event operating period. As described previously, the SDA acts as a "polishing" scrubber, or a final SO_2 control device, in order to meet the SO_2 emission limits. Its operation can be varied to meet these requirements. The post-event operating data indicate the SO_2 removal efficiency was within the normal range.

Hourly NO_x data from the Unit No. 2 CEMS in lb/MMBtu are shown in Figure 6. The 30-day rolling average emission limit for NO_x is 0.09 lb/MMBtu. NO_x emissions are controlled by the CFB boiler, as well as, by the SNCR ammonia-injection system. Pre-event hourly averages were maintained below 0.09 lb/MMBtu for the most part, in order to ensure that the 30-day rolling average limit is met. The post-event NO_x data follow the same trend.

Hourly CO data from the Unit No. 2 CEMS in lb/MMBtu are shown in Figure 7. The CO limit for Unit No. 2 is a 24-hour block average of 350 lb/hr. At full load, this would equate to 0.13 lb/MMBtu. CO emissions are controlled by the CFB boiler operation. As seen in Figure 7, pre-event hourly CO averages were maintained below 0.09 lb/MMBtu for the most part. This is an indication of good combustion taking place in the CFB boiler. The post-event CO data follow the same trend as the pre-event data.

Based on the review of the Unit No. 2 CEMS data before and after the SDA event, no discernible difference is indicated in CFB boiler or SDA operation. All systems are indicated to be operating properly and efficiently. Therefore, it is concluded that the boiler and SDA systems were functioning properly.

7.0 REVIEW OF STACK TEST DATA

Stack test data for Unit No. 2 were reviewed since startup of the unit in 2002. Initial performance tests were conducted in 2002 for PM, PM_{10}, fluorides (F), Pb, and Hg. The historic stack test data are summarized in Tables 2 and 3.

Historical PM/PM_{10} stack test data are presented in Table 2. The PM/PM_{10} emission limit of Unit No. 2 is 0.011 lb/MMBtu. The stack test data show that the unit has typically operated well below the permit limit. The highest PM stack test was experienced in 2002 (0.0107 lb/MMBtu). Other than this one high test, all other tests have resulted in emissions of 0.007 lb/MMBtu or less. The highest PM_{10} stack test was also experienced in 2002 (0.006 lb/MMBtu). All other tests have resulted in emissions of 0.005 lb/MMBtu or less.

Historical stack test data for other pollutants are presented in Table 3. The stack test data show that the unit has typically operated well below the permit limit.

Based on the review of the Unit No. 2 stack test data and the operating data discussed previously, there is no reason to believe that Unit No. 2 would not be able to continue to meet its permit limits. There is no indication that emissions would increase due to the SDA event

8.0 CONCLUSIONS

Based on review of all available data, the damage to the SDA lower hopper vessel has not caused abnormal operation of the unit, nor has it resulted in increased emissions of any air pollutant from Northside Unit No. 2. A professional engineer's certification statement is attached.

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**

   Registration Number: **19011**

2. Professional Engineer Mailing Address...

   Organization/Firm: **Golder Associates Inc.****

   Street Address: **6241 NW 23rd Street, Suite 500**

   City: **Gainesville** State: **FL** Zip Code: **32653-1500**

3. Professional Engineer Telephone Numbers...

   Telephone: **(352) 336 - 5600** ext. Fax: **(352) 336 - 6603**

4. Professional Engineer Email Address: **dbuff@golder.com**

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein*, that:

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) To the best of my knowledge, the proposed equipment addressed in this request is the same or similar to the existing equipment, and is compatible with the existing equipment, and there is reasonable assurance that the air pollutant emissions unit(s) and/or the air pollution control equipment described in this request, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(4) To the best of my knowledge, the proposed equipment replacement, repair and/or maintenance activity will not result in an increase in actual emissions from the emissions units described in this request.

David A. Buff 5/7/08

Signature Date

(seal)

* Attach any exception to certification statement.

** Board of Professional Engineers Certificate of Authorization #00001670

TABLE 2
SUMMARY OF PM/PM_{10} TEST DATA
FOR JEA NORTHSIDE UNIT NO. 2

Test Date	% Pet Coke/Coal	PM (lb/MMBtu)	PM_{10} (lb/MMBtu)
Permit Limit =		0.011	0.011
5/20/2002	pet coke		0.0044
5/30/2002	pet coke	0.007	
6/29/2002	coal	0.004	0.006
9/24/2002	70/30	0.00408	
12/18/2002	75/25	0.0107	
2/26/2003	81/19	0.003	0.004
6/11/2003	82/18	0.005	0.003
9/17/2003	72/28	0.007	0.005
9/24/2003	83/17	0.005	0.004
12/12/2003	82/18	0.004	0.002
1/13/2004	coal	0.004	
1/27/2004	50/50	0.004	
2/25/2004	80/20		0.004
2/25/2004	82/18		0.003
3/25/2004	80/20	0.005	
5/20/2004	82/18	0.005	
6/8/2004	coal	0.0019	
8/10/2004	80/20	0.0024	
8/11/2004	80/20	0.0002179	
8/19/2004	83/17	0.004	
12/20/2004	82/18	0.0049	
3/3/2005	82/18	0.0044	0.0025
2/22/2006	81/19	0.004	0.003
2/27/2007	87/13	0.004	0.003

TABLE 3
SUMMARY OF OTHER POLLUTANT EMISSIONS FROM JEA NORTHSIDE UNIT NO. 2

Test Date	% Pet Coke/Coal	Mercury (lb/hr)	VOC (lb/hr)	Lead (lb/hr)	Fluoride (lb/hr)	Sulfuric Acid Mist (lb/hr)	Ammonia (ppm)	Dioxins/Furans (lb/hr)
Permit Limit =		0.03	14	0.07	0.43	1.1	N/A	N/A
5/20/2002	pet coke	0.00077	0	0.016	0.261	3.13		
6/16/2002	pet coke					16.88		
6/29/2002	coal	0.0027	0.1	0.148	0.29	0.43		
7/25/2002	pet coke		3.67			0		
8/21/2002	coal			0.25				
9/24/2002	70/30			0.049				
11/26/2002	coal			0.018				
12/6/2002	coal			0.015				
1/13/2004	coal	0.021		0.00096				
1/14/2004	coal				0.0881		1.17	1.80E-10
1/27/2004	50/50	0.024		0.0023				
1/28/2004	50/50				0.0478		0.325	
6/8/2004	coal	0.00098		0.0013				
6/9/2004					0.1309		0.521	
8/10/2004	80/20							
8/11/2004	80/20			0.0013	0.0149		0.27	

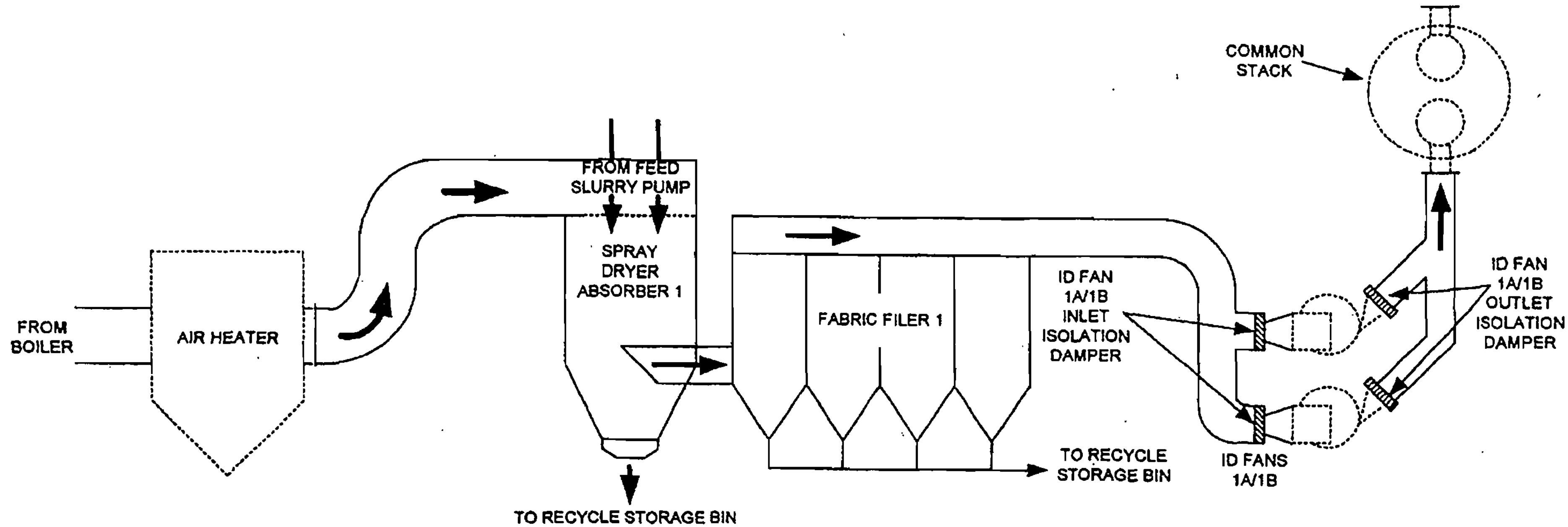


Figure 1
Air Quality Control System Flow Diagram
Northside Generating Station Unit 2
Figure 1 AQCS Overview.docx

Source: Golder, 2008.

REV.	SCALE:	
DESIGN	SL	05/06/08
CADD	--	--
CHECK	DB	05/07/08
REVIEW	DB	05/07/08

Golder Associates

APPENDIX A

The NO_x in the flue gas is measured by an analyzer installed in the stack for each individual boiler. The amount of NO_x detected (ppm) in the flue gas for each boiler is indicated at the operator console in the CEMS shelter. The NO_x emissions are also displayed on a screen on the DCS in the control room.

1.3.2 Spray Dryer Absorber

A simplified view of Spray Dryer Absorber (SDA) operation is shown in Figure 3. As the flue gas flows through the absorber it is mixed with a lime-water mixture called slurry that is injected from atomizing spray nozzles. The slurry reacts with and removes the sulfur dioxide (SO_2) and other acid gases (hydrogen fluoride [HF]) from the flue gas. It also helps to remove heavy metals from the flue gas.

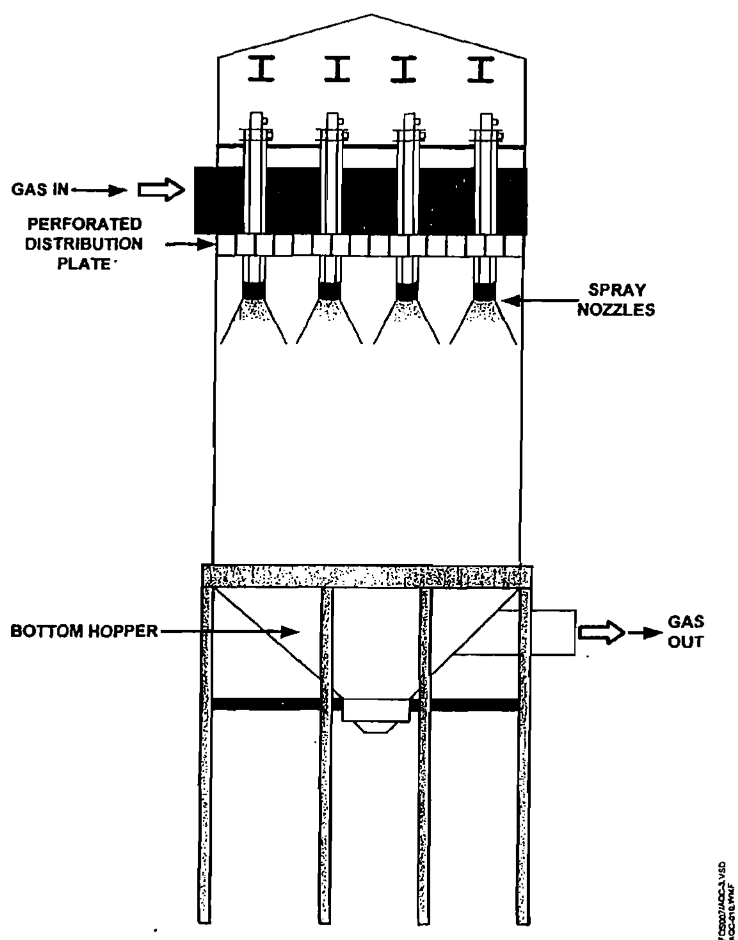


Figure 3 - SDA Operation

As the flue gas and slurry pass through the SDA, the acid gases (SO_2 and HF) react with the atomized slurry creating solid particles. Some of the solid particles fall out of the flue gas flow stream and are collected in a hopper at the bottom of the SDA. The remaining solids are captured in the Fabric Filters. The solids from the SDA and ash and solids from the fabric filters are collected and discharged to the Recycle Slurry Mix Tank.

The flue gas enters the top of the Spray Dryer Absorber through a flue gas distribution system. This distribution system uses a perforated plate that creates a plug flow flue gas pattern. The lime slurry is introduced into the SDA through fluid nozzles that atomize the slurry into fine spray droplets. The nozzles are installed in a piping manifold and spaced across the top of the SDA in a pattern that causes the slurry spray to cover the entire area of the SDA.

SO_2 is removed from the flue gas stream in two separate chemical reactions. First, the acid gases react with the calcium hydroxide in the slurry creating calcium sulfite as shown here:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 + H_2 0$$

In the second reaction, a part of the calcium sulfite is further oxidized to calcium sulfate, which is a precipitate or solid that falls to the bottom of the vessel or flows out the vessel. The reaction is shown below:

$$2CaSO_3 + O_2 \rightarrow 2CaSO_4 \downarrow$$

The acid gas (HF) reacts with the calcium hydroxide to form calcium fluoride, as shown in the following reaction:

$$2HF + Ca(OH)_2 \rightarrow CaF_2 + 2H_2O$$

The gas and solids flow to the bottom of the SDA, turn 90 degrees and exit out the side of the unit. During this change of direction, some of the solid particles and fly ash fall out of the gas into the hopper at the bottom of the SDA.

During the chemical reactions, another transformation is taking place; slurry water is being evaporated. The evaporation cools the flue gases. In order to evaporate the water, the flue gas must transfer heat to the water. This heat raises the temperature of the water to the saturation temperature. It is then used to change the water from a liquid to steam, thus lowering the flue gas temperature.

As the flue gas temperature nears the water saturation temperature, the evaporation rate decreases. This allows for more time for the liquid absorption phase to occur. The longer moisture exists in the slurry, the longer acidic gases are able to diffuse from the surface. This increases the amount of gas that can be absorbed by the slurry. The SDA is designed for an outlet temperature of 165°F to 175°F. Below 155°F the DCS will lower the slurry flow rate to maintain temperature above 155°F.

1.3.3 Lime Slurry System

The lime slurry system consists of two slurry subsystems:

- ❑ Feed Slurry Preparation System
- ❑ Absorbent Preparation System

As its name implies the SDA Feed Slurry Preparation System prepares the slurry for injection into the SDA vessel. The system does this by mixing together all of the sources of lime that is used to make up the lime slurry. These sources are:

- ❑ Recycle lime from the SDA hopper
- ❑ Recycle lime from the fabric filter hoppers
- ❑ Fresh lime delivered to the plant by truck (Absorbent Preparation System)

AQCS GUIDELINES

Revision: 3 7/28/2007

As part of our goal for continuous improvement, what follows is guidance for the operation of the SDA's and the balance of the AQCS systems. Please stay within these guidelines at all times. If the systems will not support any of these guidelines, please notify Olin Williams or Ron Beverly and provide the overall and specific plant conditions that prevented operation per these guidelines. Additionally, if you have any questions or comments for improvement, please forward these to Olin or Ron as well.

1. Target SDA outlet temperatures
   a. Full load – 175F
   b. Reduced load - raise outlet temperature to 185F and adjust reuse flow accordingly.
   c. If density is <10% at nozzles - raise outlet temperature to 185-190F
2. Maximum zone differential temperature of 10-12F degrees.
3. Minimum zone temperature of 160F. Try to maintain zone temperature as close as possible to the outlet temperature. If temperature approaches 160F, take appropriate actions to bring the temperature back within range.
4. Target density is 20%.
5. Do not allow zone differential to spread more than 12F degrees without taking appropriate measures to bring temperatures back within 10-12F guideline.
6. If ANY zone temperature drops below 160F. Monitor the ash for rocks and dryness. If poor ash quality exists, continue to discharge the ash to the emergency bin until conditions have returned to normal and ash quality is good. Log any bad ash quality conditions, new problems, or repeated problems.
7. **Do not sacrifice the quality of the ash**. If problems occur, take appropriate actions and make a log entry as to condition and actions taken.
8. Note any problems seen so that Pi can be analyzed for the appropriate time frame.

9. If the low level alarm is reached on the recycle bin, ensure that it is placed back 'in-line' and is not bypassed.
   a. If the recycle bin is bypassed in order to pull down high bag house hopper levels, maintain the bypassed condition and shutdown both rotary valves until recycle bin level can be re-established.
   b. Once high hopper levels are cleared, follow the steps required to bring the mix tank density back up to acceptable limits.
10. If mix tank density reaches <10%, it is to be recovered slowly. Use this time to verify that the recycle bin has normal levels.
   a. When density <10%, use density controller set point as follows:
   b. With density controller in auto set the set point to 3% higher than density reading.
   c. Maintain this arrangement, slowly adding ash at 3 % increments until density is >20%.
11. Keep recycle slurry storage tank level between 75-85%.
   a. When adjusting recycle slurry spray flow to the nozzles, adjust reuse water (valve 920) accordingly to prevent high or low level in the storage tank.
   b. In the event that the recycle slurry storage tank level reaches 90% or higher. DCS logic will turn off and lock out reuse water to the recycle slurry mix tank. If this occurs, storage tank level will drop to 85% and the lockout will clear. At this time, re-align ash to the normal conveyor and shut down the emergency conveyor. Put emergency conveyor & isolation slide gate back in auto.
12. SDA ash conveyor is to be kept in auto.
   In auto:
   a. A delumper trip: the ash conveyor will automatically trip.
   b. When starting the delumper: the ash conveyor will start automatically.
   c. When stopping the delumper: the ash conveyor will stop automatically.
13. SDA emergency conveyor and isolation gate are to be kept in auto. This will prevent ash from entering the mix tank when reuse valve 920 closes. After the 920 valve opens and establishes >100 gpm, manually switch to the normal ash

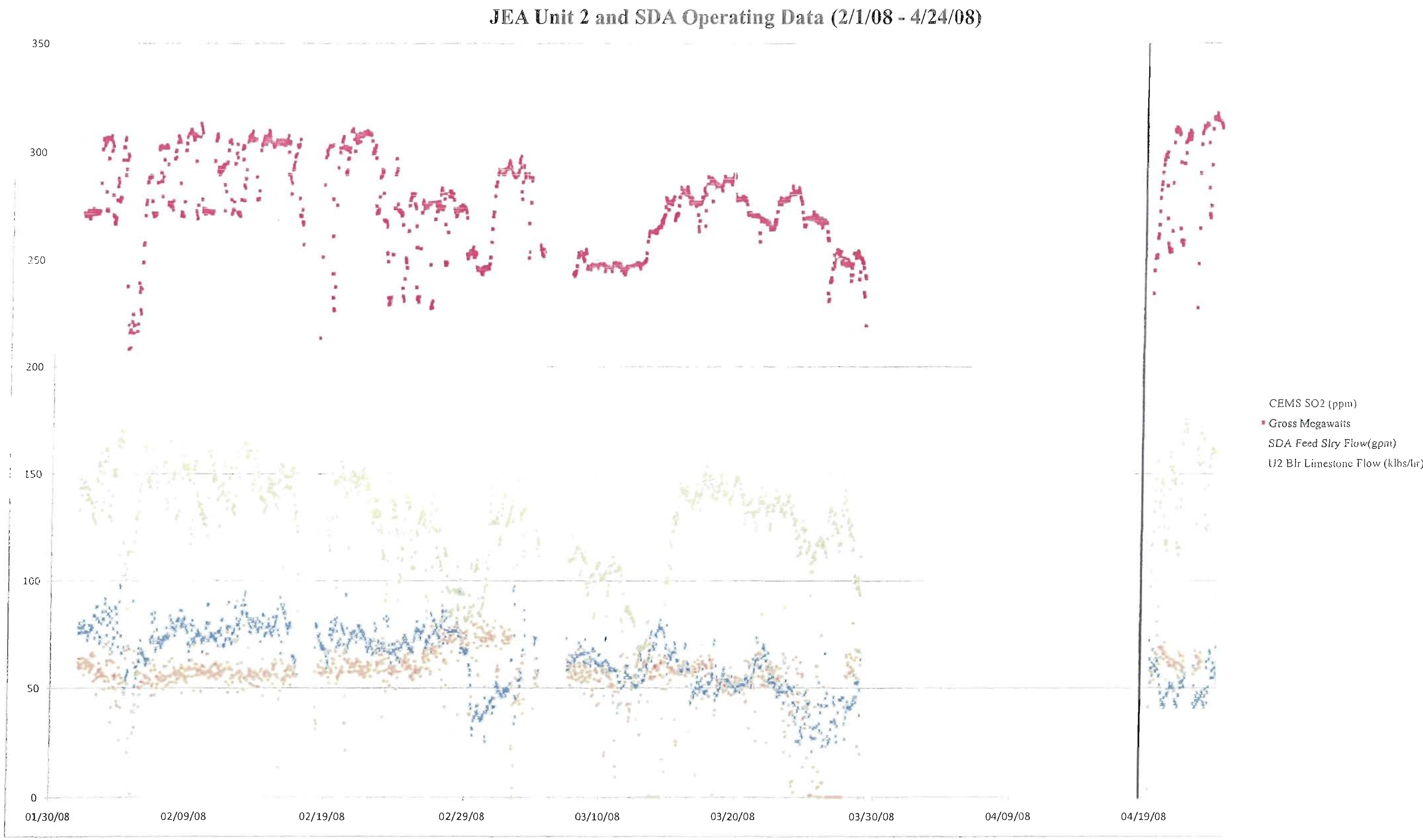
conveyor and put the emergency conveyor and isolation gate back in automatic.

Daily Actions

1. Clean all nozzles on both SDA's daily.
2. Use the emergency conveyor to discharge ash to the emergency bin three times each shift (every 4 hours).
   a. Put in the emergency discharge conveyor, close the isolation slide gate.
   b. Start the impactors (5 min. cycle)
   c. Leave emergency discharge conveyor in for no less than 15 min. to make sure all clumps are clear form conveyor. Good, fine dry ash should be the only discharge product.
3. Flush the ring header on both SDA's two times each shift by opening valve 572 for 30 seconds. Log completion into OpLog.
4. Swap the recycle slurry transfer and feed slurry transfer pumps every six hours. Swap the feed slurry pumps once a day when the nozzles are cleaned. When swapping pumps, have an operator standby to verify the floor flush drain valve is clear and flushing. Verify that all valves on the DCS screen are showing full open and full close for pump flush, if not, have operator manipulate the valves to work properly. Generate PWOs for any problems.

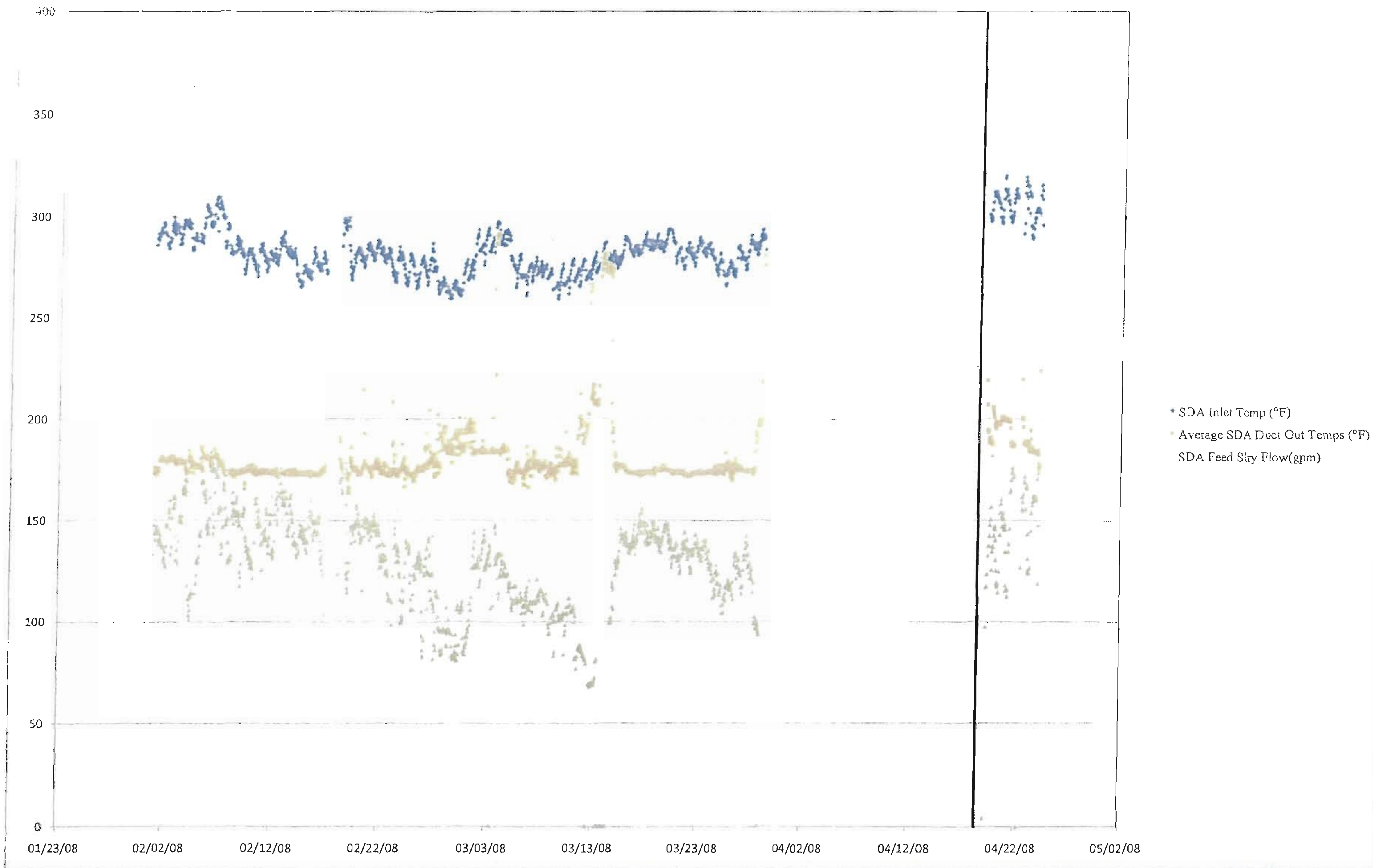
Saturday

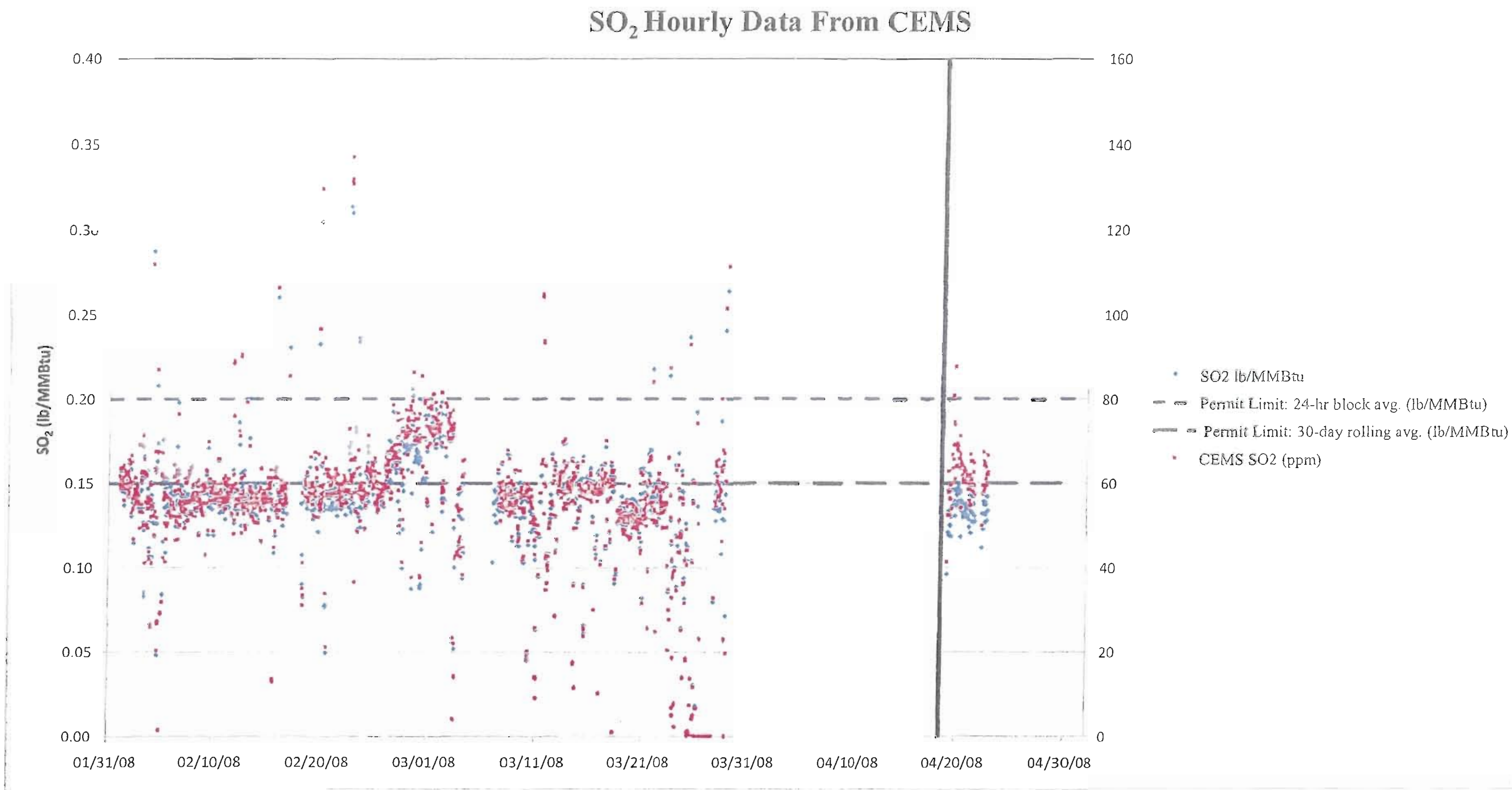
1. Each Saturday, flush the mix tank.
   a. Increase the level in the mix tank to at least 80%.
   b. Use the western drain and drain level to 60%, then close the drain valve. Ensure that the drain line is clear to ensure a good flush.
   c. After closing the drain valve, open the reuse flush valve to the drain line and allow it to flow for 20 minutes (monitor sump level during this time). Then close the valve.



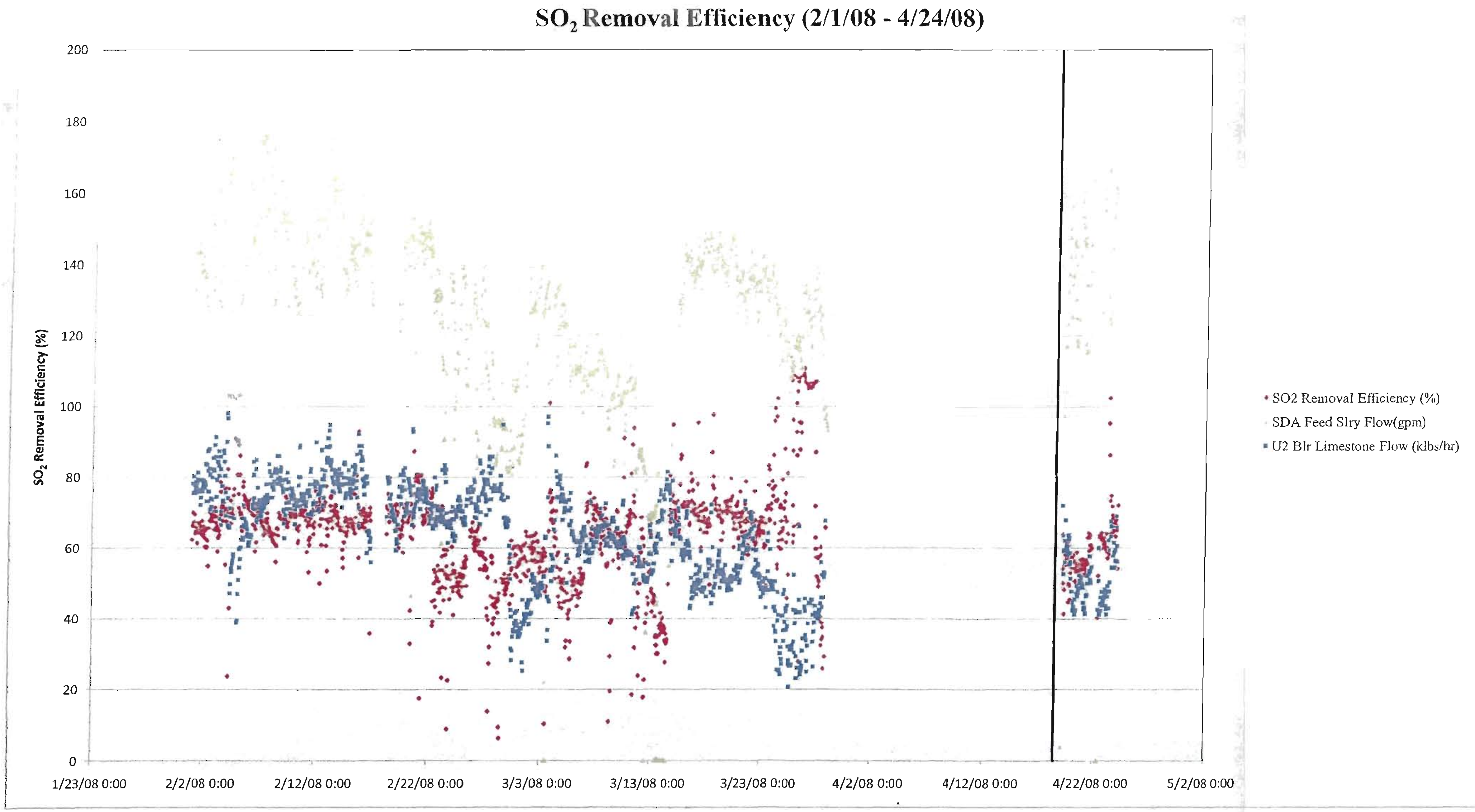
JEA Unit 2 and SDA Operating Data (2/1/08 - 4/24/08)
350
300
250
200
150
100
50
0
01/30/08
02/09/08
02/19/08
02/29/08
03/10/08
03/20/08
03/30/08
04/09/08
04/19/08
CEMS SO2 (ppm)
Gross Megawatts
SDA Feed Slry Flow(gpm)
U2 Blr Limestone Flow (klbs/hr)

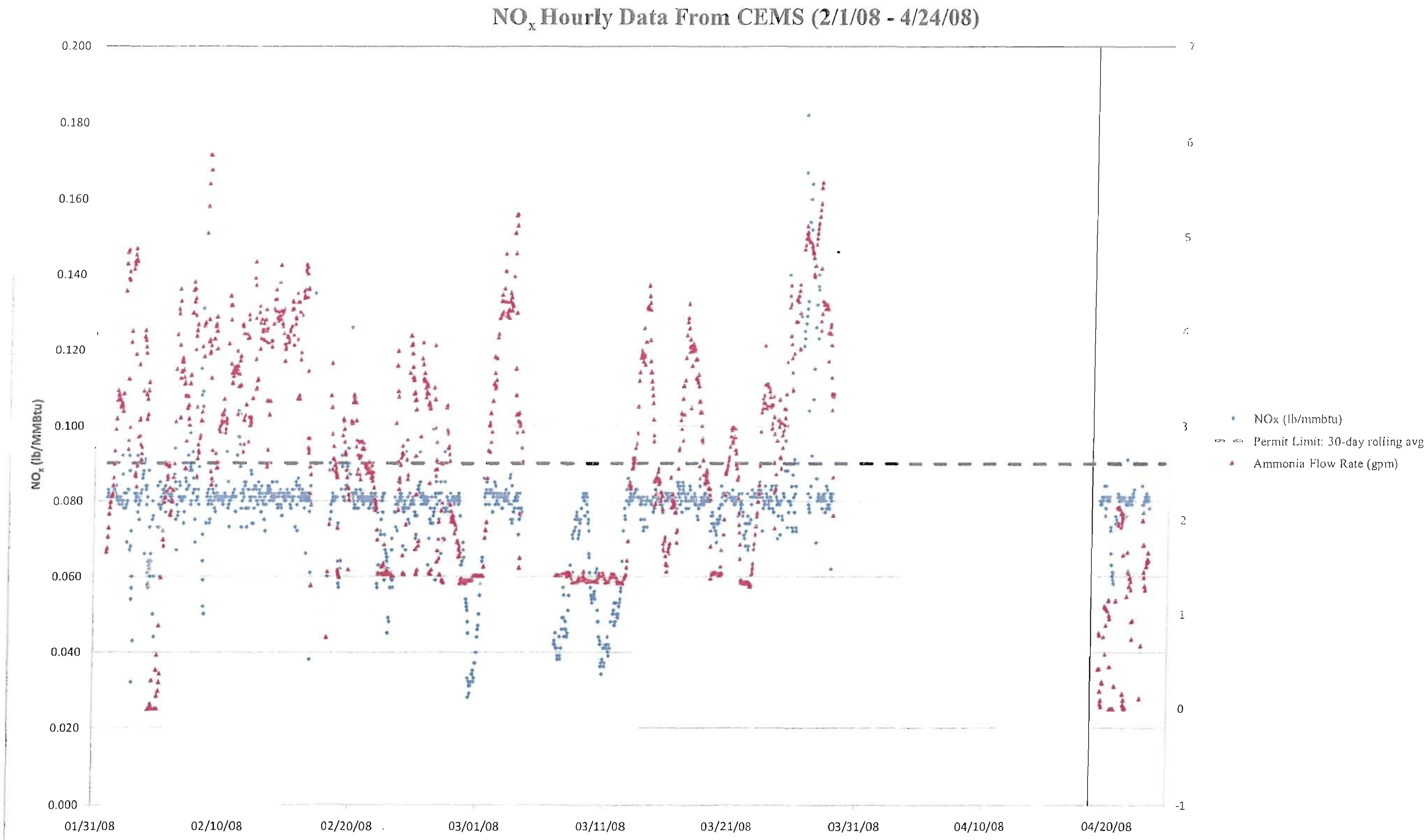
JEA Unit 2 SDA Operating Data (2/1/08 - 4/24/08)





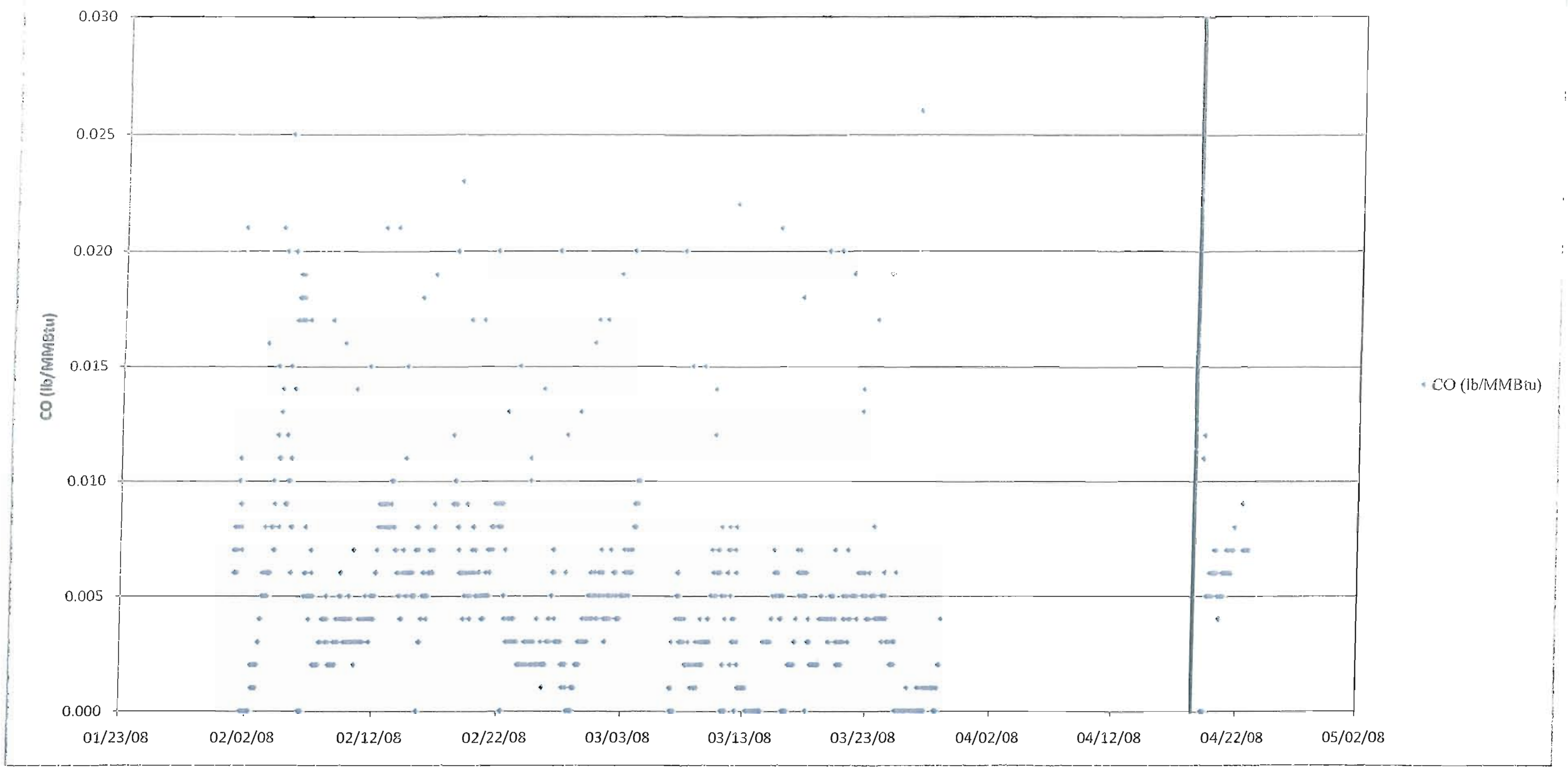
SO2 Hourly Data From CEMS
SO2 (lb/MMBtu)
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
160
140
120
100
80
60
40
20
0
01/31/08
02/10/08
02/20/08
03/01/08
03/11/08
03/21/08
03/31/08
04/10/08
04/20/08
04/30/08
SO2 lb/MMBtu
Permit Limit: 24-hr block avg. (lb/MMBtu)
Permit Limit: 30-day rolling avg. (lb/MMBtu)
CEMS SO2 (ppm)


SO2 Removal Efficiency (2/1/08 - 4/24/08)
SO2 Removal Efficiency (%)
200
180
160
140
120
100
80
60
40
20
0
1/23/08 0:00
2/2/08 0:00
2/12/08 0:00
2/22/08 0:00
3/3/08 0:00
3/13/08 0:00
3/23/08 0:00
4/2/08 0:00
4/12/08 0:00
4/22/08 0:00
5/2/08 0:00
SO2 Removal Efficiency (%)
SDA Feed Slry Flow(gpm)
U2 Blr Limestone Flow (klbs/hr)



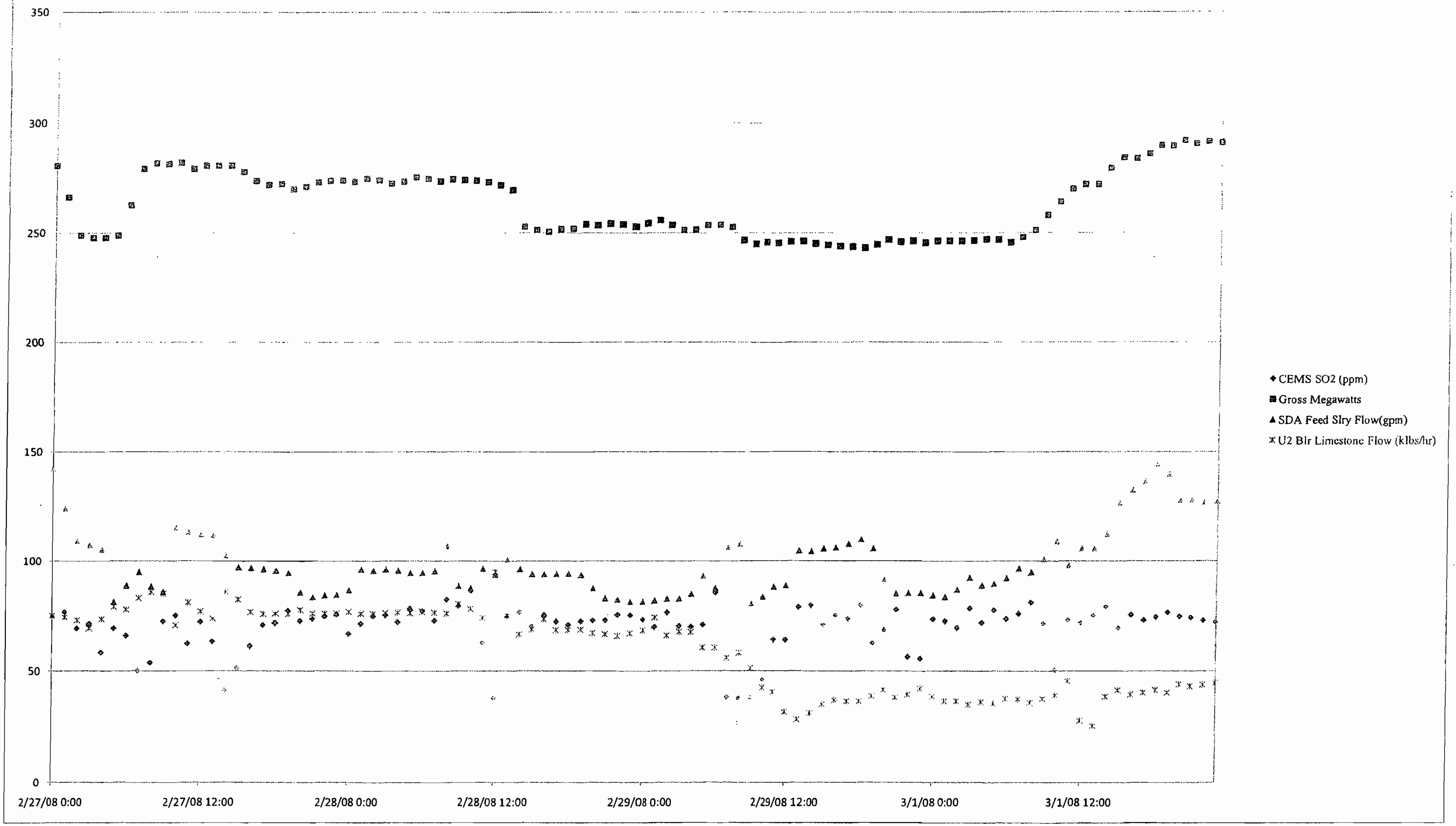
NOx Hourly Data From CEMS (2/1/08 - 4/24/08)
0.200
0.180
0.160
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
NOx (lb/MMBtu)
01/31/08
02/10/08
02/20/08
03/01/08
03/11/08
03/21/08
03/31/08
04/10/08
04/20/08
7
6
5
3
2
1
0
-1
NOx (lb/mmbtu)
Permit Limit: 30-day rolling avg
Ammonia Flow Rate (gpm)

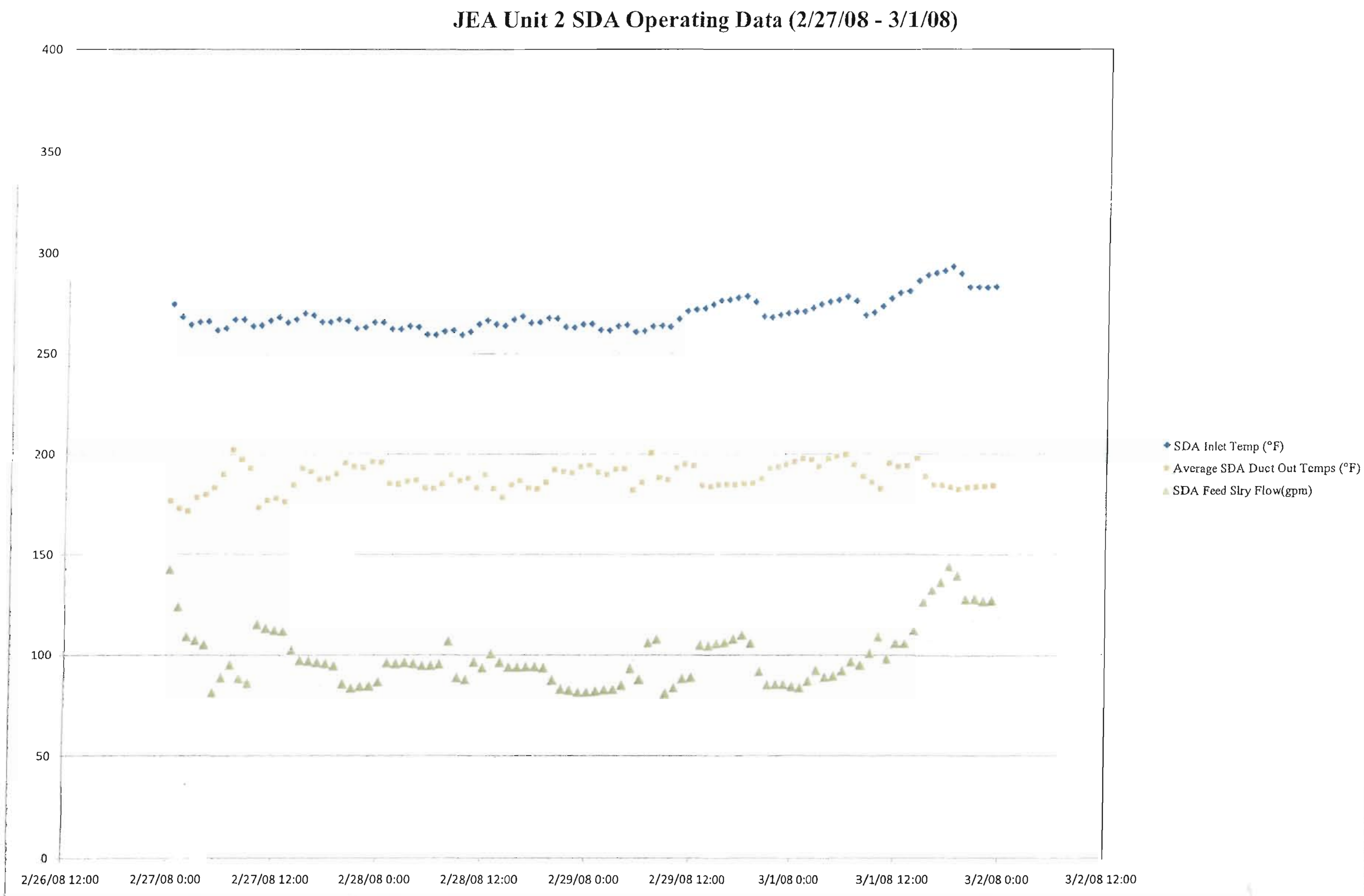
Figure 7. CO Hourly Data From CEMS



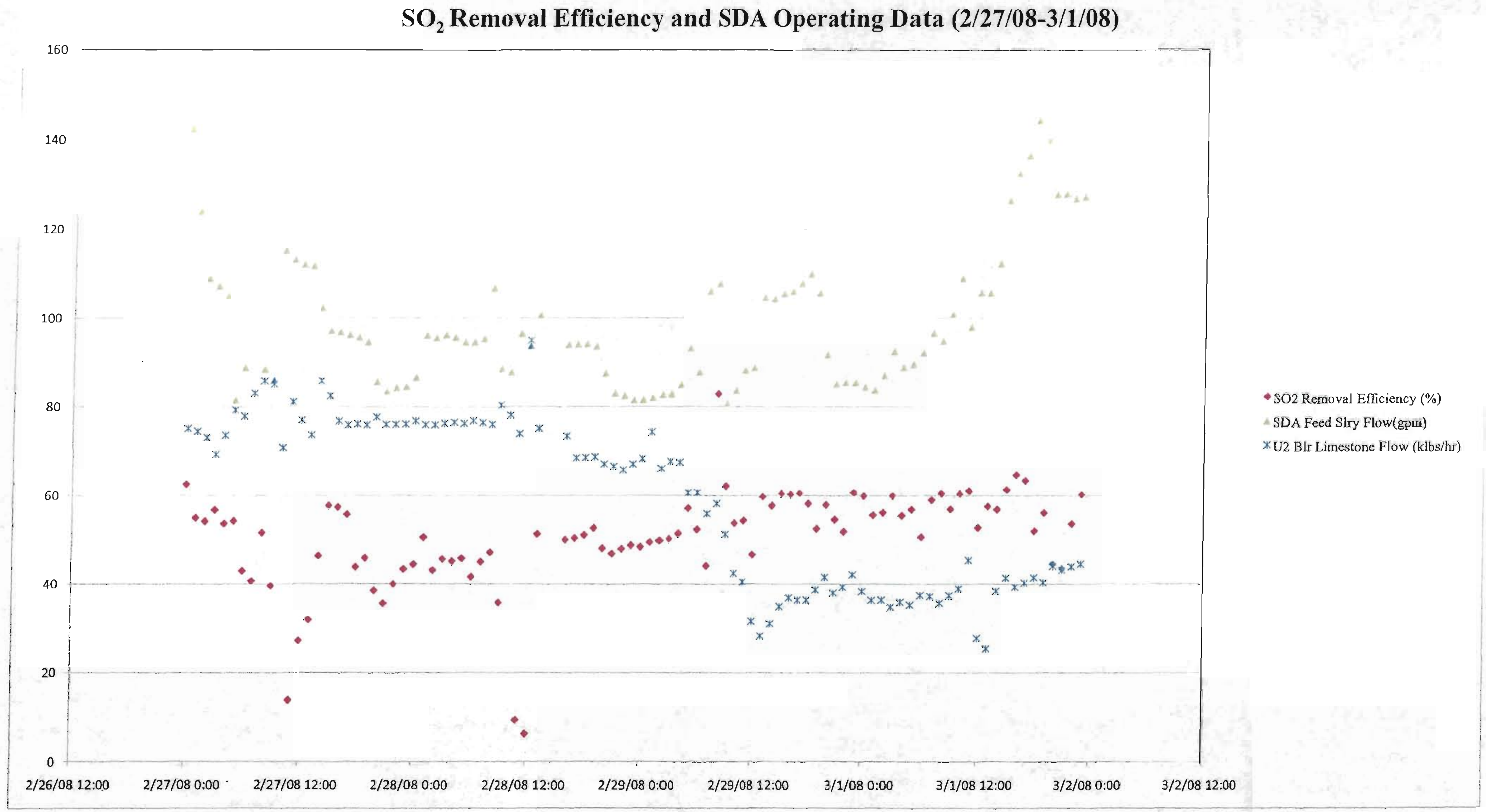
APPENDIX B

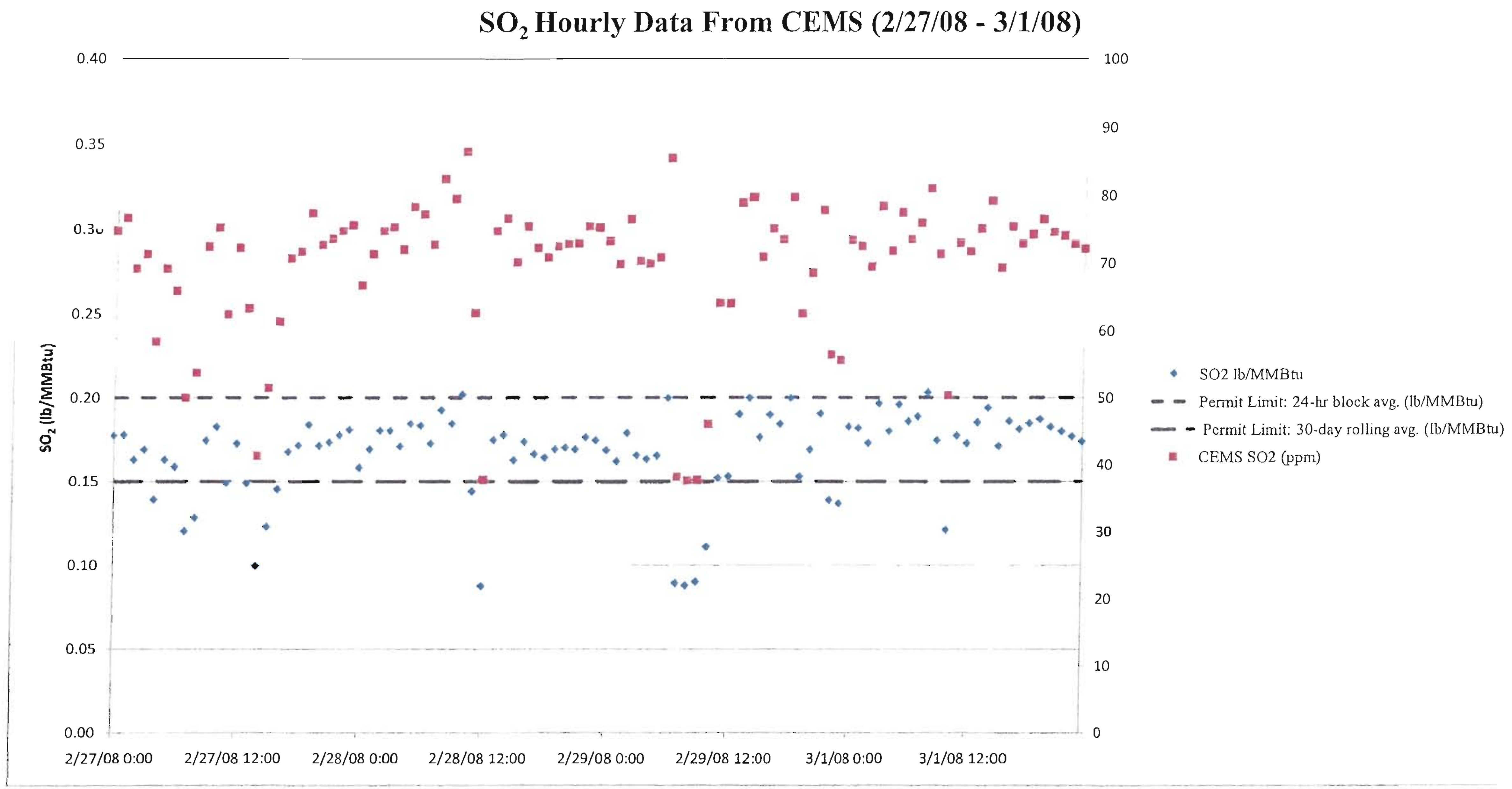
JEA Unit 2 and SDA Operating Data (2/27/08 - 3/1/08)

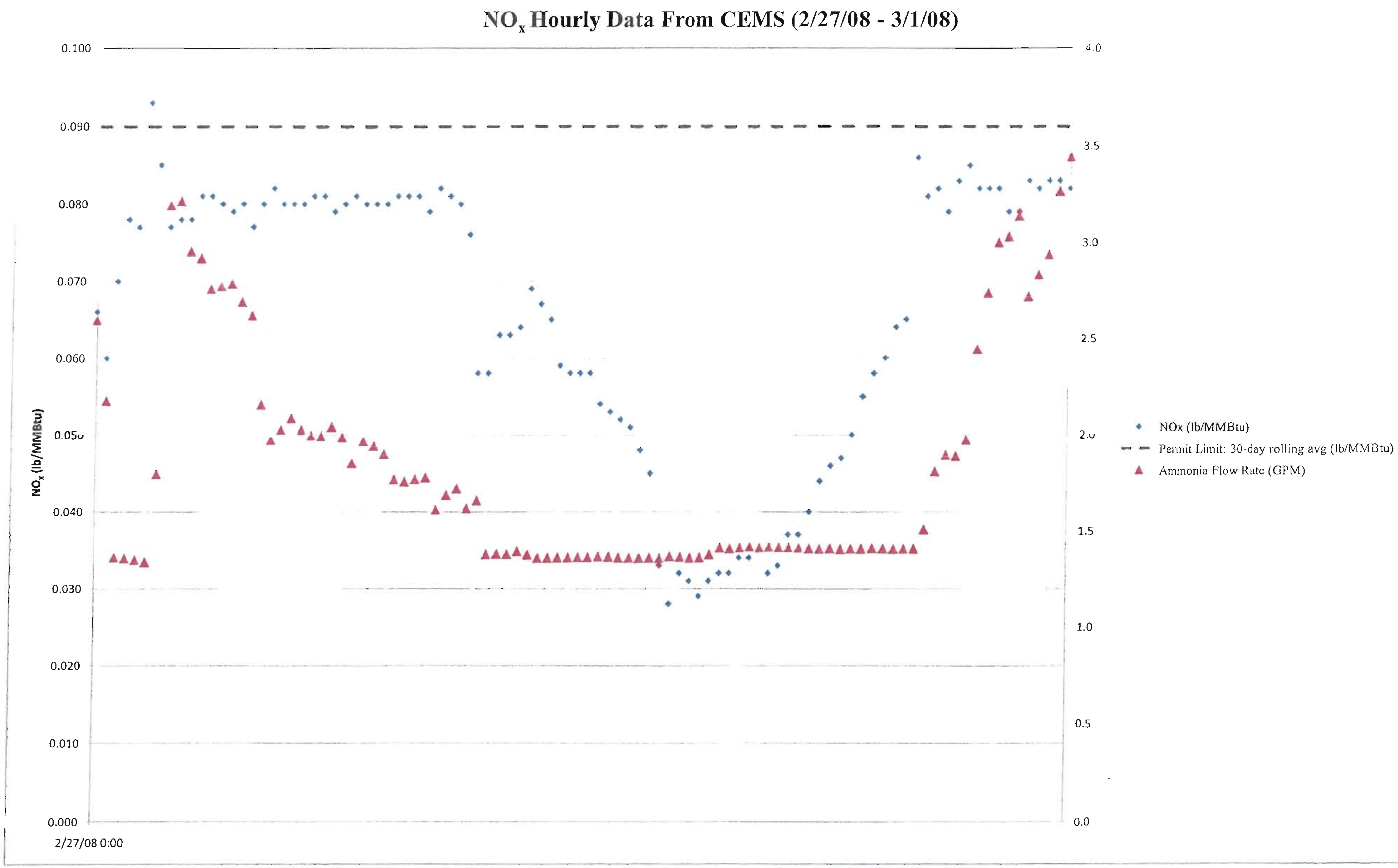




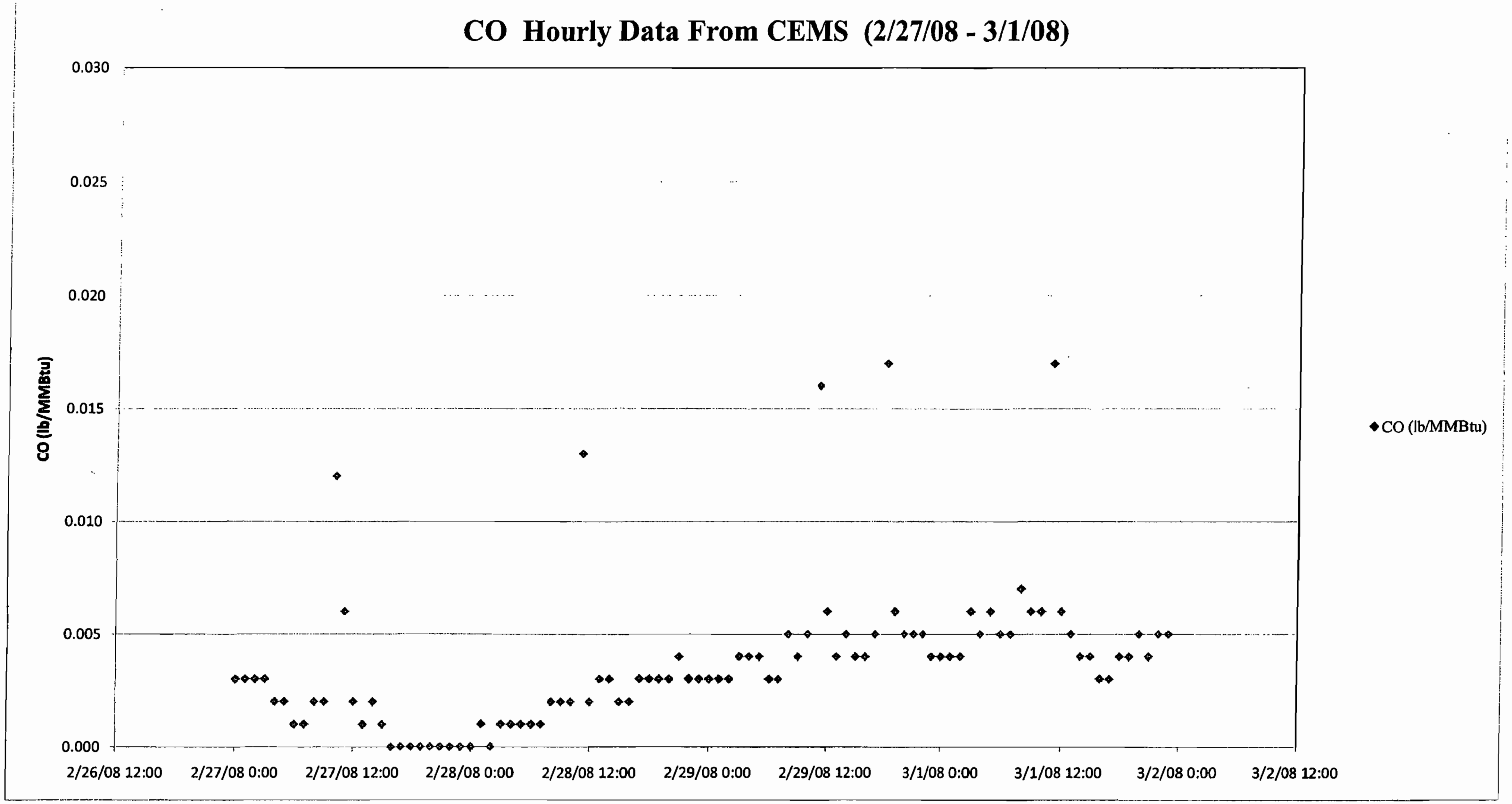
JEA Unit 2 SDA Operating Data (2/27/08 - 3/1/08)
400
350
300
250
200
150
100
50
0
2/26/08 12:00
2/27/08 0:00
2/27/08 12:00
2/28/08 0:00
2/28/08 12:00
2/29/08 0:00
2/29/08 12:00
3/1/08 0:00
3/1/08 12:00
3/2/08 0:00
3/2/08 12:00
SDA Inlet Temp (°F)
Average SDA Duct Out Temps (°F)
SDA Feed Slry Flow(gpm)


SO2 Removal Efficiency and SDA Operating Data (2/27/08-3/1/08)
160
140
120
100
80
60
40
20
0
2/26/08 12:00
2/27/08 0:00
2/27/08 12:00
2/28/08 0:00
2/28/08 12:00
2/29/08 0:00
2/29/08 12:00
3/1/08 0:00
3/1/08 12:00
3/2/08 0:00
3/2/08 12:00
SO2 Removal Efficiency (%)
SDA Feed Slry Flow(gpm)
U2 Blr Limestone Flow (klbs/hr)

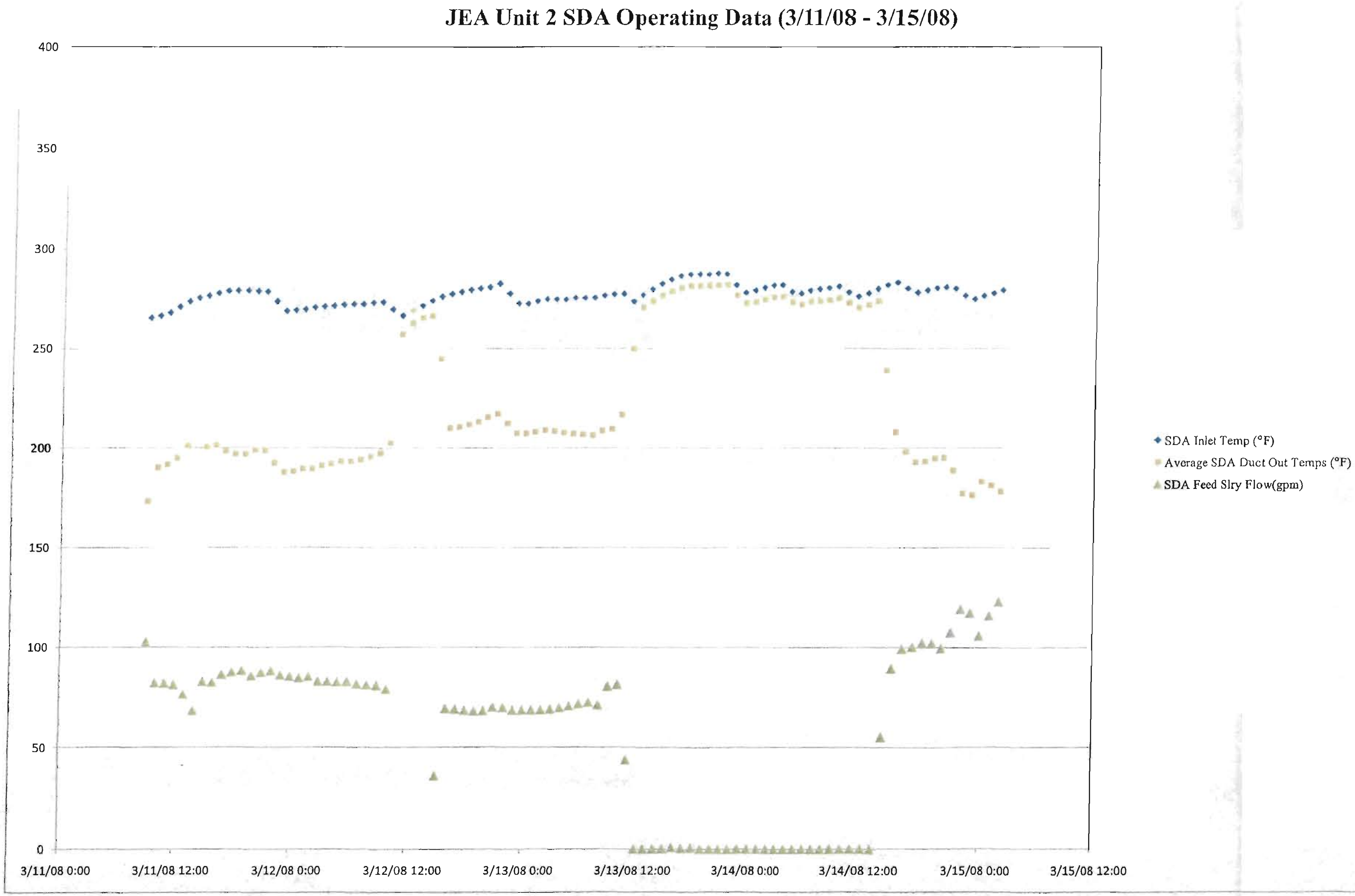

SO2 Hourly Data From CEMS (2/27/08 - 3/1/08)
SO2 (lb/MMBtu)
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
100
90
80
70
60
50
40
30
20
10
0
2/27/08 0:00
2/27/08 12:00
2/28/08 0:00
2/28/08 12:00
2/29/08 0:00
2/29/08 12:00
3/1/08 0:00
3/1/08 12:00
SO2 lb/MMBtu
Permit Limit: 24-hr block avg. (lb/MMBtu)
Permit Limit: 30-day rolling avg. (lb/MMBtu)
CEMS SO2 (ppm)



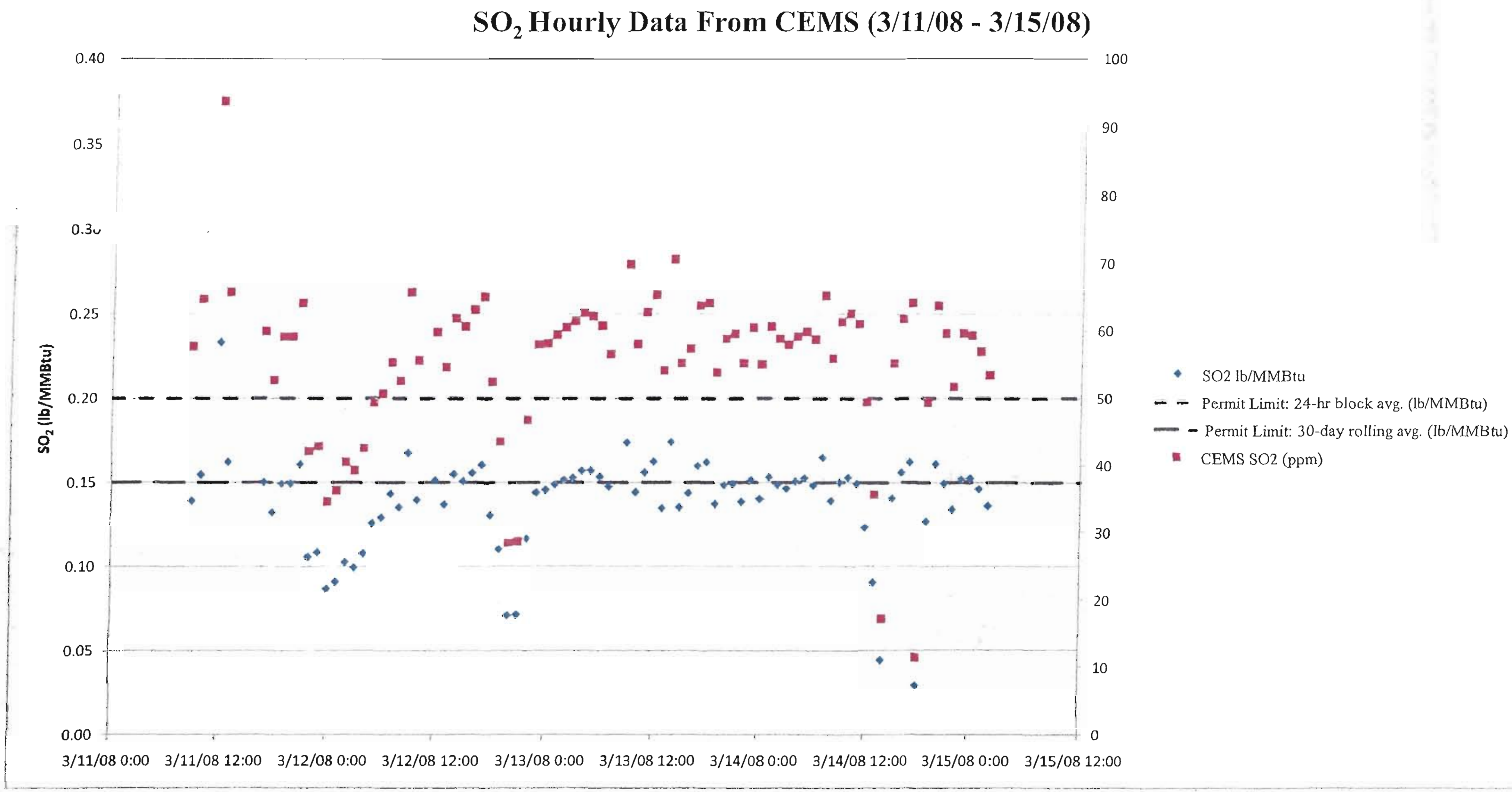
NO$_x$ Hourly Data From CEMS (2/27/08 - 3/1/08)
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
NO$_x$ (lb/MMBtu)
2/27/08 0:00
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
NOx (lb/MMBtu)
Permit Limit: 30-day rolling avg (lb/MMBtu)
Ammonia Flow Rate (GPM)



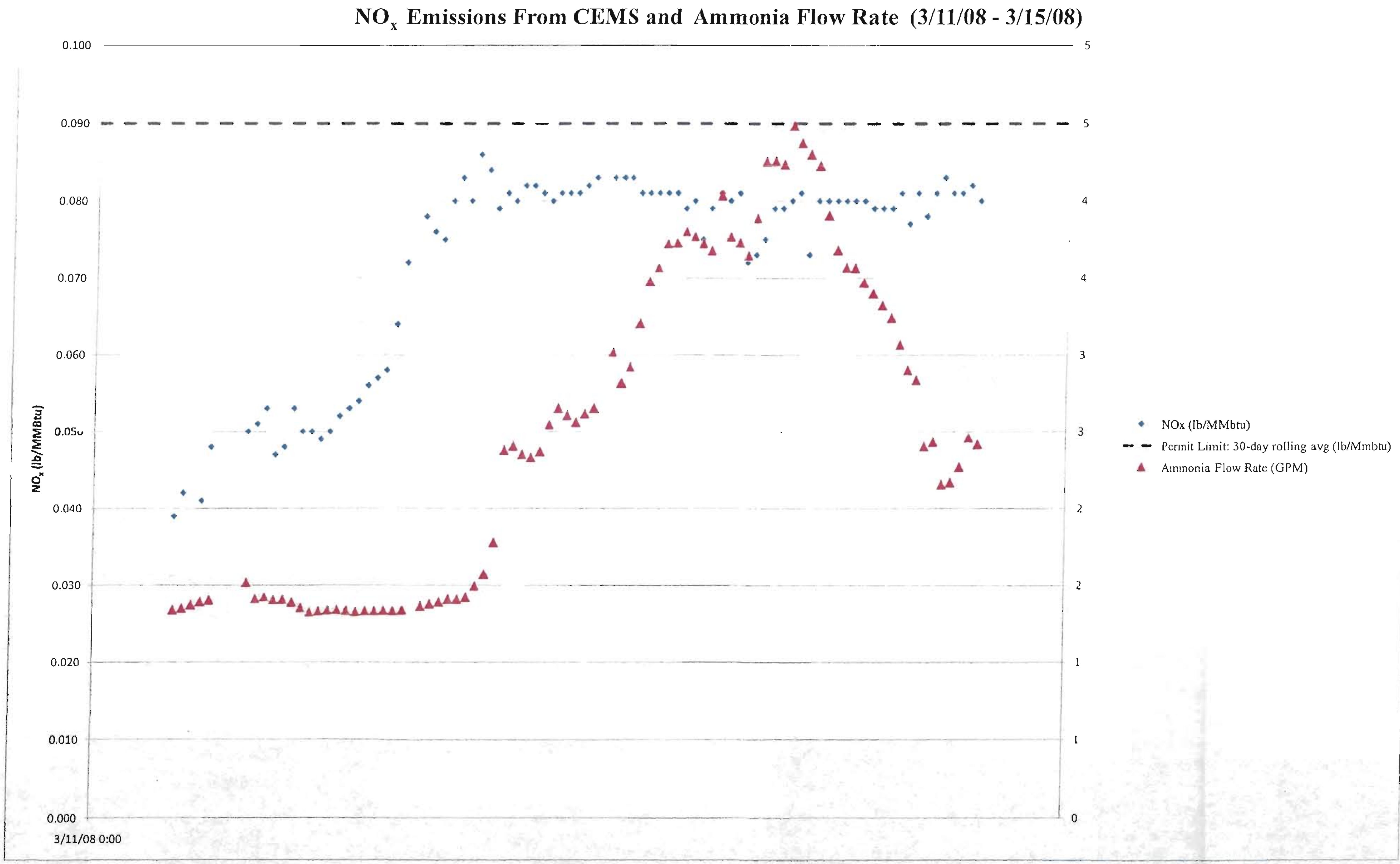
CO Hourly Data From CEMS (2/27/08 - 3/1/08)
CO (lb/MMBtu)
0.030
0.025
0.020
0.015
0.010
0.005
0.000
2/26/08 12:00
2/27/08 0:00
2/27/08 12:00
2/28/08 0:00
2/28/08 12:00
2/29/08 0:00
2/29/08 12:00
3/1/08 0:00
3/1/08 12:00
3/2/08 0:00
3/2/08 12:00
◆CO (lb/MMBtu)

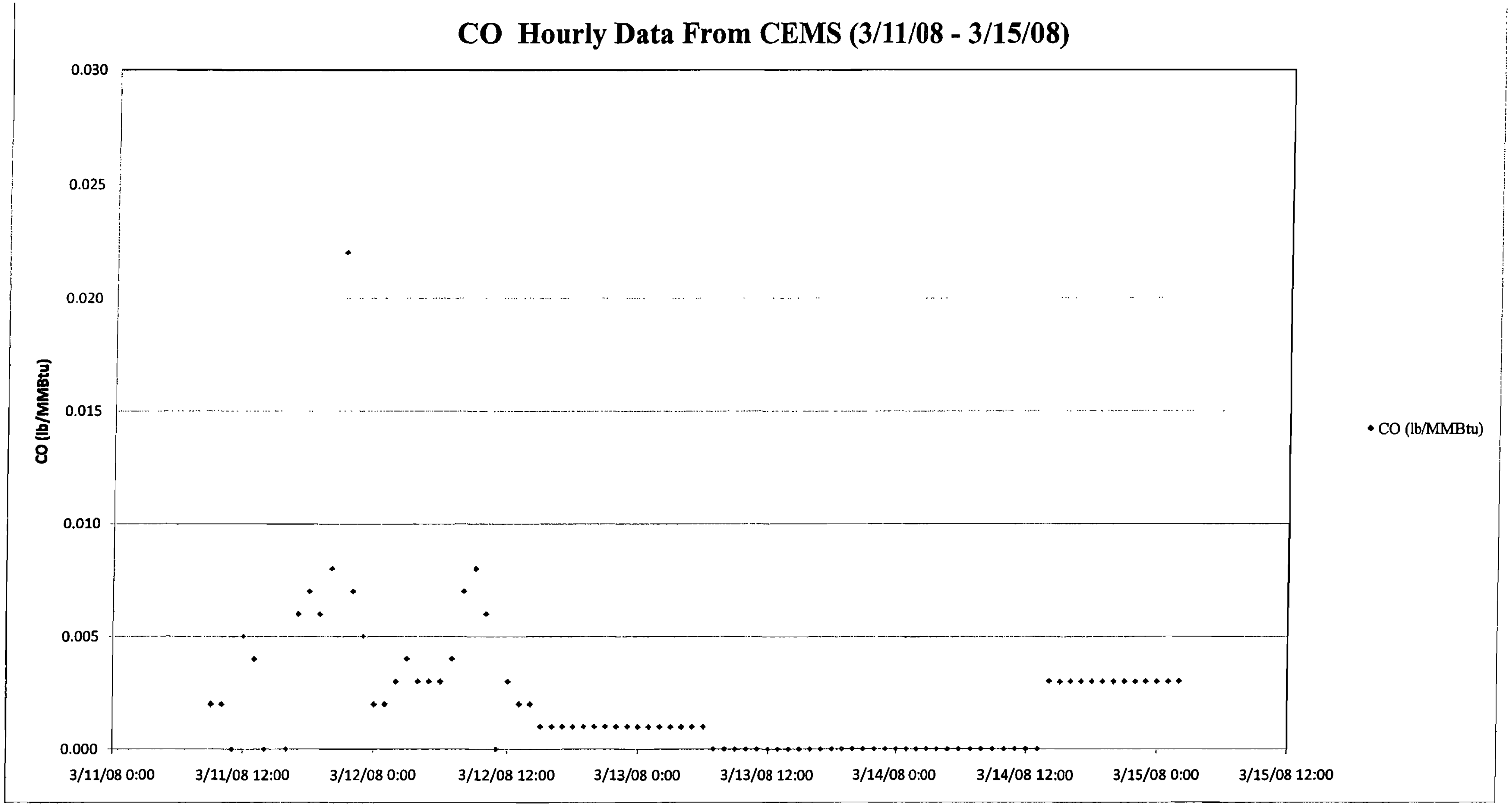


JEA Unit 2 SDA Operating Data (3/11/08 - 3/15/08)
400
350
300
250
200
150
100
50
0
3/11/08 0:00
3/11/08 12:00
3/12/08 0:00
3/12/08 12:00
3/13/08 0:00
3/13/08 12:00
3/14/08 0:00
3/14/08 12:00
3/15/08 0:00
3/15/08 12:00
SDA Inlet Temp (°F)
Average SDA Duct Out Temps (°F)
SDA Feed Slry Flow(gpm)

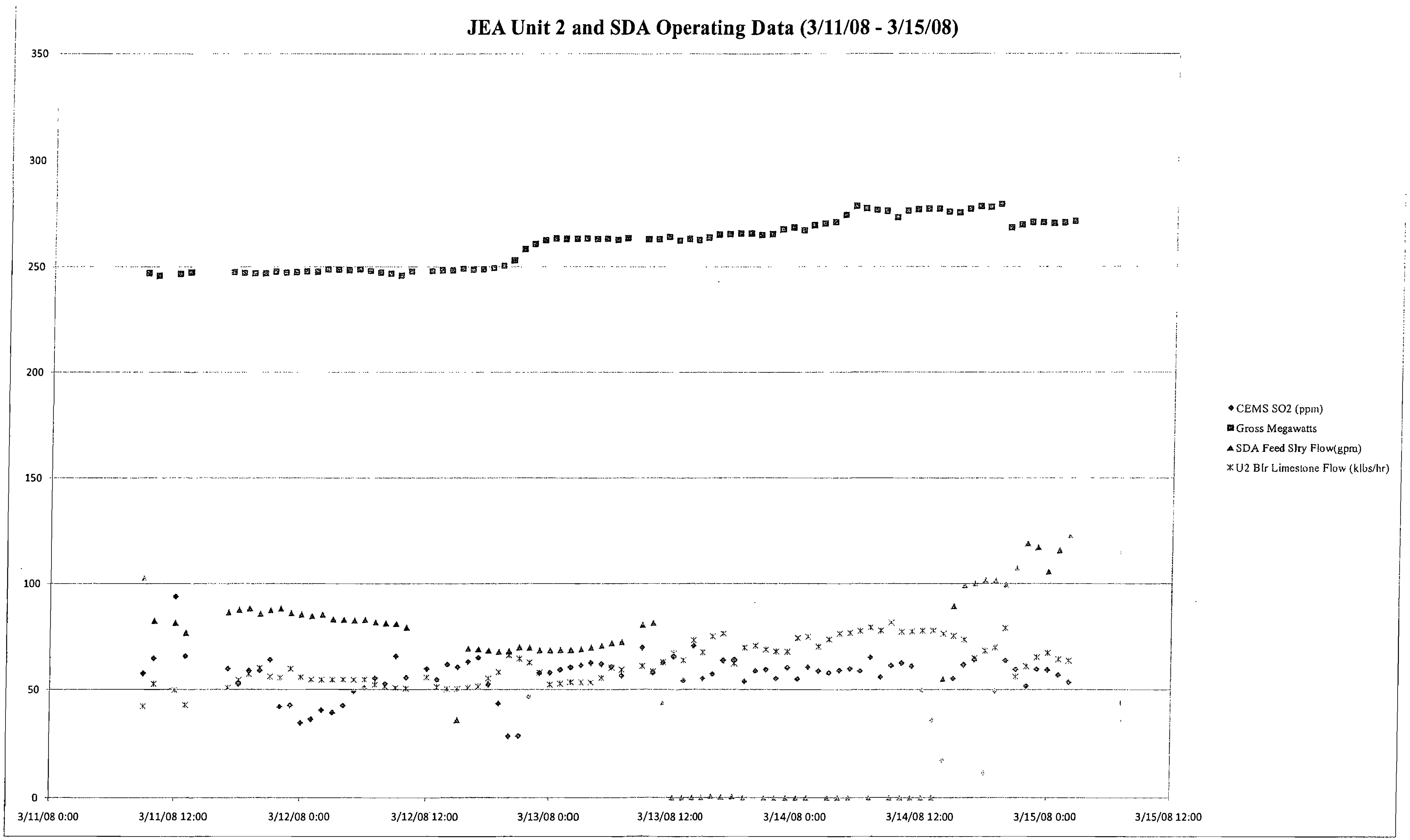


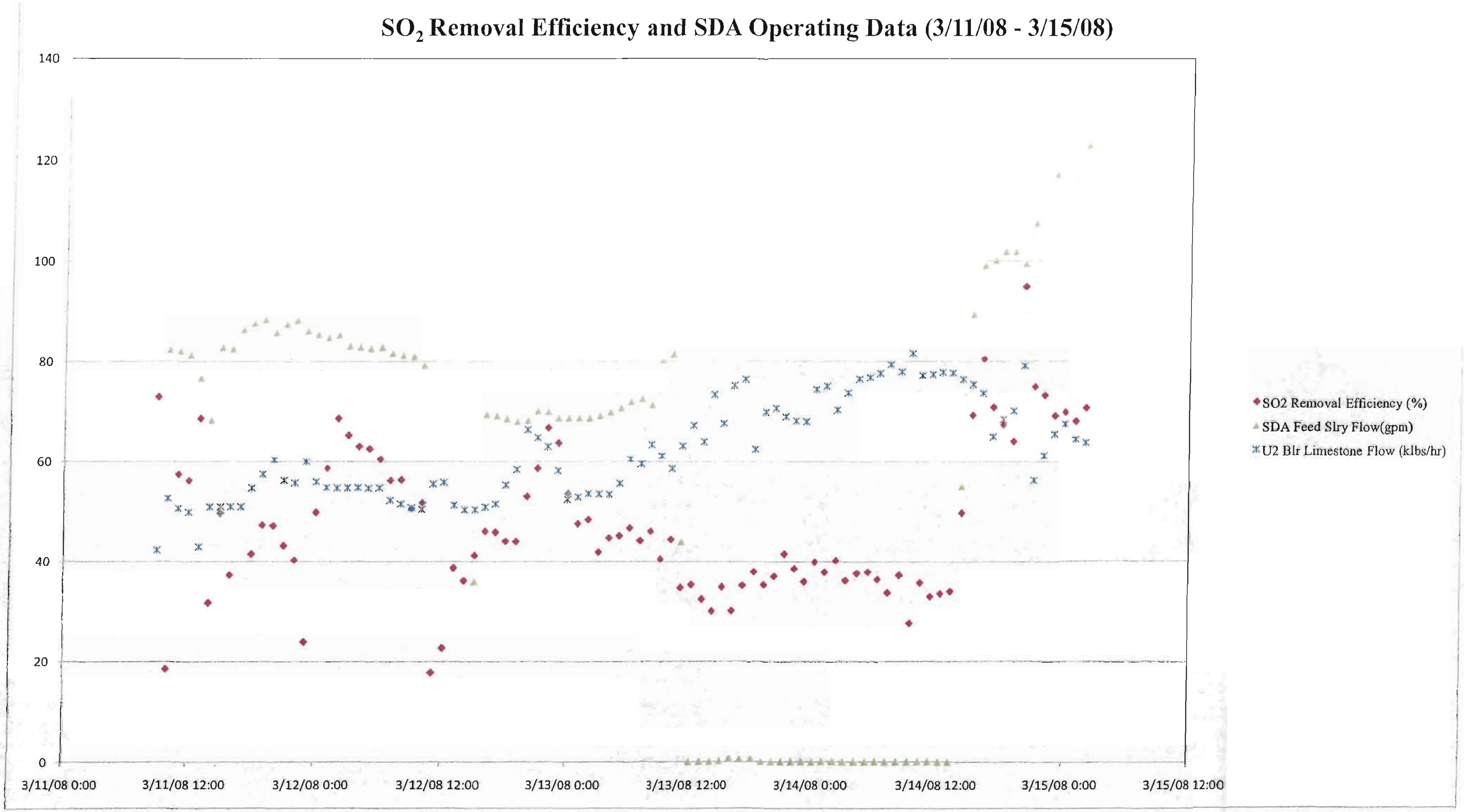
SO2 Hourly Data From CEMS (3/11/08 - 3/15/08)
SO2 (lb/MMBtu)
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
100
90
80
70
60
50
40
30
20
10
0
3/11/08 0:00
3/11/08 12:00
3/12/08 0:00
3/12/08 12:00
3/13/08 0:00
3/13/08 12:00
3/14/08 0:00
3/14/08 12:00
3/15/08 0:00
3/15/08 12:00
SO2 lb/MMBtu
Permit Limit: 24-hr block avg. (lb/MMBtu)
Permit Limit: 30-day rolling avg. (lb/MMBtu)
CEMS SO2 (ppm)


NO$_x$ Emissions From CEMS and Ammonia Flow Rate (3/11/08 - 3/15/08)
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
NO$_x$ (lb/MMBtu)
3/11/08 0:00
5
5
4
4
3
3
2
2
1
1
0
NOx (lb/MMbtu)
Permit Limit: 30-day rolling avg (lb/Mmbtu)
Ammonia Flow Rate (GPM)



CO Hourly Data From CEMS (3/11/08 - 3/15/08)
0.030
0.025
0.020
0.015
0.010
0.005
0.000
CO (lb/MMBtu)
3/11/08 0:00
3/11/08 12:00
3/12/08 0:00
3/12/08 12:00
3/13/08 0:00
3/13/08 12:00
3/14/08 0:00
3/14/08 12:00
3/15/08 0:00
3/15/08 12:00
CO (lb/MMBtu)


JEA Unit 2 and SDA Operating Data (3/11/08 - 3/15/08)
350
300
250
200
150
100
50
0
3/11/08 0:00
3/11/08 12:00
3/12/08 0:00
3/12/08 12:00
3/13/08 0:00
3/13/08 12:00
3/14/08 0:00
3/14/08 12:00
3/15/08 0:00
3/15/08 12:00
CEMS SO2 (ppm)
Gross Megawatts
SDA Feed Slry Flow(gpm)
U2 Blr Limestone Flow (klbs/hr)



SO2 Removal Efficiency and SDA Operating Data (3/11/08 - 3/15/08)
140
120
100
80
60
40
20
0
3/11/08 0:00
3/11/08 12:00
3/12/08 0:00
3/12/08 12:00
3/13/08 0:00
3/13/08 12:00
3/14/08 0:00
3/14/08 12:00
3/15/08 0:00
3/15/08 12:00
SO2 Removal Efficiency (%)
SDA Feed Slry Flow(gpm)
U2 Blr Limestone Flow (klbs/hr)

APPENDIX C

JEA UNIT 2 STACK TESTS (2002)

Test Date	Gross MW (MW)	Fuel %Petcoke/ %Coal	SDA Inlet Temp. (°F)	Average SDA Outlet Temp. (°F)	Fabric Filter Outlet Temp. (°F)	SDA Feed Slurry (gpm)	Total Limestone Flow (klb/hr)	Unit 2 SDA Inlet Lead Emissions (lb/hr)	Unit 2 SDA Inlet Lead Emissions (lb/MMBtu)	Unit 2 Stack Lead Emissions (lb/hr)	Unit 2 Stack Lead Emissions (lb/MMBtu)	Unit 2 SDA Inlet Mercury Emissions (lb/hr)	Unit 2 SDA Inlet Mercury Emissions (lb/MMBtu)	Unit 2 Stack Mercury Emissions (lb/hr)	Unit 2 Stack Mercury Emissions (lb/MMBtu)	Unit 2 SDA Inlet Fluoride Emissions (lb/hr)	Unit 2 SDA Inlet Fluoride Emissions (lb/MMBtu)	Unit 2 Stack Fluoride Emissions (lb/hr)	Unit 2 Stack Fluoride Emissions (lb/MMBtu)
5/20/2002	283	petcoke	284	--	157	159	65	<0.008	<0.0000024	0.023	7.49E-06	0.00004	1.54E-08	0.00165	5.80E-07	0.353	0.00013	0.293	0.00011
5/20/2002	283	petcoke	284	--	157	159	65	<0.008	<0.0000024	0.009	2.82E-06	0.00011	3.79E-08	0.00047	1.60E-07	0.344	0.00010	0.412	0.00016
5/20/2002	283	petcoke	284	--	157	159	65	0.009	3.31E-06	<0.0063	1.91E+00	0.00010	3.49E-08	0.00019	6.82E-08	0.171	0.00005	0.078	0.00004
6/29/2002	293	coal	308	172	169	185	42	--	--	0.01648	0.00E+00	--	--	0.00333	1.06E-06	--	--	0.23	0.0001
6/29/2002	293	coal	308	172	169	185	42	--	--	0.32170	0.00E+00	--	--	0.00163	5.07E-07	--	--	0.36	0.0001
6/29/2002	293	coal	308	172	169	185	42	--	--	0.10590	0.00E+00	--	--	0.00301	9.15E-07	--	--	0.29	0.0001
8/21/2002	283	coal	317	175	174	198	31	0.142	5.65E-05	0.25[a]	--	--	--	--	--	--	--	--	--
8/21/2002	283	coal	317	180	174	198	31	0.125	4.53E-05	0.25[a]	--	--	--	--	--	--	--	--	--
8/21/2002	283	coal	317	187	174	198	31	0.161	5.53E-05	0.25[a]	--	--	--	--	--	--	--	--	--
9/24/2002	--	70/30	--	--	--	--	--	--	--	0.035	1.28E-05	--	--	--	--	--	--	--	--
9/24/2002	--	70/30	--	--	--	--	--	--	--	0.045	1.61E-05	--	--	--	--	--	--	--	--
9/24/2002	--	70/30	--	--	--	--	--	--	--	0.067	2.41E-05	--	--	--	--	--	--	--	--
11/26/2002[b]	210	coal	314	184	182	146	59	--	--	0.018	--	--	--	--	--	--	--	--	--
12/6/2002	259	coal	288	185	180	176	65	--	--	0.010	3.61E-06	--	--	--	--	--	--	--	--
12/6/2002	259	coal	288	185	180	176	65	--	--	0.018	6.93E-06	--	--	--	--	--	--	--	--
12/6/2002	259	coal	288	185	180	176	65	--	--	0.017	6.45E-06	--	--	--	--	--	--	--	--
							Limit =			0.07				0.03				0.43	

[a] Data in stack test presented as an average of 3 runs.

[b] One run only.

JEA UNIT 2 STACK TESTS (2004)

		SDA Inlet - Mercury Emissions				Stack - Mercury Emissions					Stack	Stack
Test Date	Fuel %PC / %Coal	Total Mercury (lb/hr)	Particulate Bound Mercury (lb/hr)	Oxidized Mercury (lb/hr)	Elemental Mercury (lb/hr)	Total Mercury (lb/hr)	Total Mercury Removal (%)	Particulate Bound Mercury (lb/hr)	Oxidized Mercury (lb/hr)	Elemental Mercury (lb/hr)	Hydrogen Fluoride (lb/hr)	Lead - Total (lb/hr)
1/13/04	coal	5.21E-02	3.33E-02	4.91E-04	1.83E-02	1.97E-02	63.6	2.10E-05	9.43E-05	1.96E-02	--	--
1/13/04	coal	4.00E-02	2.38E-02	1.51E-03	1.47E-02	2.14E-02	59.5	2.07E-05	8.28E-05	2.13E-02	--	--
1/13/04	coal	5.48E-02	3.58E-02	4.24E-04	1.86E-02	<1.93E-02	64.3	2.11E-05	<6.33E-05	1.92E-02	--	--
1/27/04	50/50	5.43E-02	3.46E-02	1.75E-04	1.95E-02	<2.08E-02	57.9	<2.04E-06	<4.08E-05	2.08E-02	<0.0487	4.71E-03
1/27/04	50/50	7.87E-02	4.41E-02	4.13E-04	3.42E-02	<2.33E-02	54.2	<2.05E-06	<4.10E-05	2.32E-02	<0.0381	5.09E-04
1/27/04	50/50	6.55E-02	4.11E-02	4.04E-04	2.40E-02	<2.67E-02	48.4	<2.11E-06	8.45E-05	2.66E-02	<0.0567	1.71E-03
6/8-9/2004	coal	2.25E-02	2.10E-02	3.79E-04	1.15E-03	<5.88E-04	97.4	<2.10E-05	<4.20E-05	5.56E-04	<0.197	<2.34E-03
6/8-9/2004	coal	1.72E-02	1.64E-02	4.41E-04	3.84E-04	<1.85E-03	89.6	<2.08E-05	1.15E-04	1.73E-03	<0.1928	<9.43E-04
6/8-9/2004	coal	1.91E-02	1.90E-02	3.75E-05	6.56E-05	<5.06E-04	97.5	<2.11E-05	4.43E-04	5.27E-05	<0.0034	<5.38E-04
8/10-11/2004	80/20	8.42E-03	8.04E-03	2.33E-04	1.42E-04	<4.63E-04	94.8	<2.15E-05	1.40E-04	3.12E-04	<0.0145	<0.00223
8/10-11/2004	80/20	1.00E-02	9.68E-03	2.14E-04	1.12E-04	<2.17E-04	97.9	<3.17E-05	1.16E-04	8.46E-05	<0.0150	<0.00124
8/10-11/2004	80/20	7.18E-03	7.08E-03	5.08E-05	5.08E-05	<8.70E-05	98.8	<2.18E-05	<4.35E-05	5.44E-05	<0.0152	<0.000387
8/10-11/2004	80/20	1.28E-02	1.25E-02	2.25E-04	5.11E-05	<1.050E-04	99.2	<4.20E-05	<4.20E-05	6.30E-05		
Limit (lb/hr) =						3.00E-02					0.43	7.00E-02

JEA UNIT 1 STACK TESTS (2002)

Test Date	Gross MW (MW)	SDA Inlet Temp. (°F)	Average SDA Outlet Temp. (°F)	Fabric Filter Outlet Temp. (°F)	SDA Feed Slurry (gpm)	Total Limestone Flow (klb/hr)	Unit 1 Stack Lead Emissions (lb/hr)	Unit 1 Stack Lead Emissions (lb/MMBtu)	Unit 1 Stack Outlet Mercury Emissions (lb/hr)	Unit 1 Stack Outlet Mercury Emissions (lb/MMBtu)	Unit 1 Stack Outlet Fluoride Emissions (lb/hr)	Unit 1 Stack Outlet Fluoride Emissions (lb/MMBtu)
7/30/2002	285	--	--	--	--	--	0.0046	1.57E-06	1.8E-03	6.10E-07	0.061	2.04E-05
7/30/2002	285	--	--	--	--	--	0.0075	2.50E-06	1.3E-04	4.30E-08	0.058	1.96E-05
7/30/2002	285	--	--	--	--	--	0.0217	7.36E-06	9.9E-05	3.40E-08	0.247	8.31E-05
9/25/2002	297	290	176	174	169	42	0.0037	1.31E-06	1.8E-03	6.24E-07	0.260	1.00E-04
9/25/2002	297	290	176	174	169	42	0.0027	9.86E-07	1.2E-03	4.32E-07	0.140	1.00E-04
9/25/2002	297	290	176	174	169	42	0.0028	9.87E-07	1.2E-03	4.73E-07	0.190	1.00E-04
						Limit=	0.07		0.03		0.43	