6-21-95

TO Marty

DATE 6/21 TIME 10:10

WHILE YOU WERE OUT

M Michelle [illegible]

of

PHONE 407/[illegible]-650

AREA CODE NUMBER EXTENSION

TELEPHONED		PLEASE CALL	✓	~~WILL~~ CALL AGAIN	
RETURNED YOUR CALL				CALL IMMEDIATELY	
CAME TO SEE YOU				WANTS TO SEE YOU	

CAlled BACK 6/21/95

MESSAGE

Letter 3/95 to Bruce -

Amendment Request

By [illegible]

TO: Teresa

thru AL.

6/19 Marty
I think we may have discussed pts. Pls advise. clm

U.S. Generating Company

Indiantown Generating Plant

RECEIVED
JUN 15 1995
Bureau of
Air Regulation

Martin Costello
Department of Environmental Protection
Bureau of Air Regulation
Blair Stone Road
Tallahassee, FL

Re: Indiantown Generating Facility
PSD-FL-168
PA 90-31

Dear Mr. Costello:

Indiantown Cogeneration, L.P. (ICL) has previously submitted emissions test as protocol to FDEP on April 17, 1995. The protocol outlines the test methods to be used for demonstration of compliance in accordance with Special Condition 19 of the PSD permit (Condition of Certification II (1) A.3.b).

As we have discussed, the protocol contains several minor deviations from the list provided at Special Condition 19. The attached table presents the permit requirement versus the proposed method with an explanation for the deviation.

As we discussed previously, these are minor changes and the Method 25A change will improve the accuracy of the compliance test. As a minor change to the permit, a $250.00 application fee is required. A check in this amount is enclosed.

First coal fire is anticipated to occur June 19, 1995 starting the 180 day clock for completing compliance testing. ICL expects to reach full load, shortly thereafter, starting the 60 day clock. Thus, we need approval to complete our compliance tests by mid August in order to maintain compliance with the requirements of Special Condition 18, Condition of Certification II (1)A3a, and 40 CFR 60.8. I look forward to working with you to obtain approval of these methods and the emission test protocol.

Doing business in Florida as Indiantown Cogeneration, L.P. Limited Partnership
P.O. Box 1620 • 19140 SW Warfield Blvd. • Indiantown, Florida 34956 • 407-597-6200 • Fax 407-597-6210

In addition to the EPA guidance document and application fee, I have enclosed revised tables from the protocol to more accurately reflect our testing program. Enclosed please find revised tables 1-1 and 3-1. Please call me at (301) 718-6973 if you have any questions or concerns.

Sincerely,

Michelle Griffin

Michelle Griffin

cc: H. S. Oven, Jr., FDEP
C. H. Fancy, FDEP

Indiantown Generating Facility
Emissions Test Method Changes

Permit	Protocol	Explanation
7, 7C or 19	7E	We believe that this is a typographical error in the permit and that FDEP intended to approve 7E. 7C is not usual for coal fired facilities.
3	3 & 3A	Because of the methods approved, method 3A is more appropriate for use during SO_2, NO_x & VOC tests
201 or 201A	5	Because the permit limit for PM_{10} is the same, ICL proposes to use the Methods results for PM and PM_{10}.
18 or 25	18 and 25A	Method 18 will be used for methane. Method 25A will be used for total hydro carbons. Recent guidance from EPA recommends use of 25A for sources emitting less than 50 ppm VOC as carbon. EPA recommends Method 18 in conjunction with Method 25. (Guidance document enclosed).

Clean Air Engineering

Parkway West Industrial Park • 1601 Parkway View Drive • Pittsburgh, PA 15205

Phone 412/787-9130 • Fax 412/787-9138

Mr. William D. Harper, P.E.
Bechtel Power Corporation
9801 Washingtonian Boulevard
Gaithersburg, Maryland 20878-5356

PROTOCOL FOR COMPLIANCE TESTING

To be performed for:
BECHTEL POWER CORPORATION

Conducted at:
INDIANTOWN GENERATING PLANT
MARTIN COUNTY, FLORIDA

Client Reference No: 22019-TSC-007
CAE Project No: 7454-2P
Revision 0: March 31, 1995
Revision 1: April 14, 1995
Revision 2: May 11, 1995

1. PROJECT OVERVIEW (CONTINUED)

1.2 Scope (continued)

The air sampling program is summarized below:

Table 1-1: PC Boiler Stack Test Program Scope

Parameter	Methodology	Test Duration	Replicates
oxygen [1]	EPA 3		
carbon dioxide [1]	EPA 3		
oxygen	EPA 3A	60 min.	3
carbon dioxide	EPA 3A	60 min.	3
total particulate (PM and PM_{10})	EPA 5	120 min.	3
sulfur dioxide	EPA 6C	60 min.	3
nitrogen oxides	EPA 7E	60 min.	3
sulfuric acid mist	EPA 8	60 min.	3
opacity	EPA 9	60 min.	3
carbon monoxide	EPA 10	60 min.	3
lead	EPA 12	120 min.	3
fluoride	EPA 13B	60 min.	3
non-methane hydrocarbons	EPA 18 and 25A	60 min.	3
mercury	EPA 101A	120 min.	3
beryllium	EPA 104	120 min.	3
arsenic	EPA 108	120 min.	3
ammonia	EPA Ammonia (Draft)	120 min.	3

[1] EPA Method 3 will be conducted simultaneously with EPA Methods 5, 8, 12, 13B, 101A, and 108.

Table 1-2: Coal, Limestone and Flyash Test Program Scope

Parameter	Methodology [1]	Test Duration	Replicates
opacity	EPA 9	60 min.	3
fugitive emissions	EPA 22	15 min.	5

[1] Each source may not require both visible and fugitive emissions to demonstrate compliance.

3. SCHEDULE OF ACTIVITIES

The following schedule is proposed for the compliance testing program:

Table 3-1: Schedule of Activities

Day	Location	Activity	Test Method	Runs	Duration	Sample Volume
1-2		Mobilize to Project site				
		Set up test equipment				
3	Stack	Beryllium [3]	EPA 104	3	120 min.	60 dscf
		Arsenic [3]	EPA 108	3	120 min.	60 dscf
	Bag Filters [1]	Opacity	EPA 9	3	60 min.	NA
		Fugitive Emissions	EPA 22	5	15 min.	NA
4	Stack	Oxygen	EPA 3A	3	60 min	continuous
		Carbon Dioxide	EPA 3A	3	60 min.	continuous
		Sulfur Dioxide [2]	EPA 6C	3	60 min.	continuous
		Nitrogen Oxide [2]	EPA 7E	3	60 min	continuous
		Carbon Monoxide [2]	EPA 10	3	60 min.	continuous
		Methane [2]	EPA 18	3	60 min.	3 liter
		Total Hydrocarbons [2]	EPA 25A	3	60 min.	continuous
		Lead [3]	EPA 12	3	120 min	60 dscf
		Fluorides [3]	EPA 13B	3	60 min.	30 dscf
5	Stack	Particulate/Ammonia [3]	EPA 5/NH_3 (draft)	3	120 min	60 dscf
		Sulfuric Acid Mist [3]	EPA 8	3	60 min.	30 dscf
		Opacity	EPA 9	3	60 min.	N/A
6		Dismantle test equipment				
		Return to basing point				

[1] Coal, limestone and flyash handling bag filters visible emissions will be determined while each specific process is operating at required conditions.
[2] Pounds per hour emission rates for instrumental methods will be calculated using the volumetric flow determined from EPA Method 12 and EPA Method 13B.
[3] EPA Method 3 samples will be collected and analyzer with an Orsat® analyzer to determine the molecular weight of the flue gas.

TOTAL P.04

EMISSION MEASUREMENT TECHNICAL INFORMATION CENTER
GUIDELINE DOCUMENT

Applicability of Methods 25 and 25A

SUMMARY

State regulations sometimes require testers to measure VOC emissions from sources where the concentration of VOC is less than 50 ppm as carbon. We recommend that Method 25A be used to measure the concentration of VOC emissions from these kind of sources.

DISCUSSION

There are three EPA test methods that are appropriate for measuring total VOC emissions. These are Methods 25, 25A, and 25B. Method 25 is designed to measure the destruction efficiency of incinerators used to control VOC emissions from coating sources. While it would be generally applicable to any source, it has a relatively high minimum detectable level of 50 ppm, as carbon. This would limit its usefulness at sources where VOC emissions are less than 50 ppm.

We recommend that testers use Method 25A for measuring VOC emissions from sources that have VOC emissions that are below the minimum detectable level of Method 25. This approach is not without problems. When Method 25A is used to measure unknown VOC emissions, there is a potential negative bias in the results. In addition, if methane is present in the source emissions, a separate method would be required to measure the methane and subtract it from total organic emissions measured by Method 25A to determine VOC. Despite these problems, Method 25A is the only EPA procedure that can measure total VOC at the levels present at some sources.

Prepared by Gary McAlister, Emission Measurement Branch
Technical Support Division, OAQPS, EPA

EMTIC GD-011
January 25, 1991

EMISSION MEASUREMENT TECHNICAL INFORMATION CENTER
GUIDELINE DOCUMENT

MEMORANDUM

SUBJECT: EPA's VOC Test Methods 25 and 25A

FROM: John B. Rasnic, Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: Air, Pesticides, and Toxics Management Division Directors
Regions I and IV

Air and Waste Management Division Director
Region II

Air, Radiation, and Toxics Division Director
Region III

Air and Radiation Division Director
Region V

Air, Pesticides, and Toxics Division Director
Region VI

Air and Toxics Division Directors
Regions VII, VIII, IX and X

As a result of requests from industry, Regional Offices and State programs, we have reviewed our guidance regarding the use of Methods 25 and 25A for measuring gas stream volatile organic compounds (VOC) concentration. Information obtained during this review has resulted in the following revised guidance, which is effective immediately and which supersedes all previous guidance on this matter. This revision has been coordinated with the other divisions within the Office of Air Quality Planning and Standards.

The EPA has decided to add an option 3 to permit further the use of Method 25A in lieu of Method 25 under certain conditions. Therefore, our new guidance is as follows. The EPA mandates the use of Method 25 for measuring gas stream VOC concentration when determining the destruction efficiency (DE) of afterburners. it also allows the use of Method 25A, in lieu of Method 25, under any of the following circumstances: 1) when the applicable regulation limits the exhaust VOC concentration to less than 50 ppm; 2) when the VOC concentration at the inlet of the control system and the required level of control are such to result in exhaust VOC concentrations of 50 ppm or less; or 3) if, because of the high efficiency of the control device, the anticipated VOC concentration at the control system exhaust is 50 ppm or less, regardless of the inlet concentration.

Further, if a source elects to use Method 25A under option 3, above, the exhaust VOC concentration must be 50. ppm or less and the required DE must be met for the source to have demonstrated compliance. If the Method 25A test results show that the required DE apparently has been met, but the exhaust concentration is above 50 ppm, this is an indicator that Method 25A is not the appropriate test method and that Method 25 should be used.

Prepared by Vishnu S. Katari
(202) 564-4004
Emissions Measurement Center, OAQPS

EMTIC GD-32
April 4, 1995

BACKGROUND

The primary industry impacted by this policy is the printing industry, which has consistently claimed that the Method 25 test procedure is too expensive and cumbersome to be used as a compliance demonstration tool. They have stated that current state-of-the-art technology afterburners routinely achieve 98-99 percent destruction efficiency, generally significantly greater than is required by regulations. As a result, control system outlet VOC concentrations are commonly less than 50 ppm, regardless of the inlet concentration.

Regulations which specify performance requirements for the subject control systems have typically been based on older technology, which was less efficient than current technology. We agree with the printing industry's claim that VOC destruction technology currently available can perform at greater levels than as specified by the regulations. It is therefore appropriate to revise our guidance on the usage of these compliance demonstration methods.

This guidance specifies the circumstances under which Method 25 and Method 25A are to be used. It will reduce the administrative burden on a significant number of regulated industrial sources but will not reduce the stringency of any currently applicable regulatory requirements.

cc: OAQPS Division Directors

I N T E R O F F I C E   M E M O R A N D U M

Date: 14-Jun-1995 11:38am EST
From: Alvaro Linero TAL
LINERO_A
Dept: Air Resources Management
Tel No: 904/921-9532
SUNCOM: 291-9532

TO: Teresa Heron TAL (HERON_T)

CC: Mike Harley TAL (HARLEY_M)

Subject: Indiantown Generating Facility, PSD-FL-168

Teresa. We received a request from Indiantown Generating to change some of the compliance test methods required in their PSD and AC Permits. They look straightforward and are all Department-approved methods and are not specifically precluded for use on the particular source.

However, according to Guidance DARM-EM-02, combustion sources are to use Method 25. This seems to apply to incinerators of VOCs but I can't tell if it applies to power plants. We often just require CO emissions limits and good combustion practices at power plants. An ASP can be obtained by presentation of data from tests conducted using both methods. Method 25A is requested by the applicant because Method 25 is not accurate below 50 ppm. The VOC restriction on the source is so low that it may indicate the source is in compliance whether or not it really is. This reminds me of the Sugar Industry case with Method 3 (Orsat) used in conjunction with a very low and non-detectable emission rate. They back up their case with Guidelines prepared by EPA in 1991 and 1995.

Please consult with Mike Harley before telling them an ASP is required or before you make any changes in the VOC test method for Indiantown. I'll send him a copy of the materials we received.

Memorandum

Florida Department of
Environmental Protection

DARM-EM-02

TO: District Air Program Administrators
County Air Program Administrators
Bureau of Air Regulation Engineers

FROM: Howard L. Rhodes, Director
Division of Air Resources Management

DATE: March 17, 1994

SUBJECT: Guidance on The Use of EPA Methods 18, 25 and 25A for Measuring Gas Stream Volatile Organic Compounds (VOC) Concentration

This memo is to provide guidance concerning the appropriate EPA methods for use in the measurement of VOC concentrations. The commonly used methods are EPA Methods 25 and 25A, and occasionally EPA Method 18. This memo does not preclude the requirement for obtaining an Alternate Standard or Procedure (ASP) per 17-297.620, F.A.C.

Method 25 is the recommended method for the measurement of total gaseous nonmethane organic emissions from most air pollution sources - especially combustion sources. The lower limit of detection for EPA Method 25 is 50 ppmv as carbon. The presence of water vapor and carbon dioxide may positively bias (observed emissions higher than true emissions) the results of the method. Pursuant to 40 CFR 60 Appendix A, the bias is not considered to be significant if the product of the volumetric concentrations of water vapor and carbon dioxide is not greater than 100. For example, the bias is not significant for a source having 10 percent CO_2 and 10 percent water vapor, but it would be significant for a source near the detection limit having 10 percent CO_2 and 20 percent water vapor. EPA Method 25 shall be the required VOC measurement technique whenever it is required by Chapter 17-296, F.A.C., or 17-297, F.A.C., or an applicable federal NSPS or NESHAP. It shall also be the required VOC measurement technique for combustion sources, sources controlled by VOC incinerators (afterburners), and sources that emit an unknown mix of organic compounds. Any owner who wants to use another measurement technique (i.e., EPA Method 25A) in lieu of EPA Method 25 must apply for and obtain approval of an ASP.

Method 25A is the recommended method for measurement of compounds consisting of only carbon and hydrogen, or a single organic solvent if the analyzer used during the testing is calibrated for this solvent. EPA EMTIC Guideline Document EMTIC GD-011 and the attached EPA memo dated October 25, 1993, recommends the use of EPA Method 25A if the VOC concentration at the outlet of an incinerator is less than 50 ppmv as carbon. However, the presence of partially oxidized organic compounds in a combustion source or VOC incinerator (afterburner) may cause the results obtained with Method 25A to be biased low. EPA Method 25A shall be the required VOC measurement technique whenever it is required by Chapter 17-296, F.A.C., or 17-297, F.A.C., or an applicable federal NSPS or NESHAP. Any owner who wants to use another measurement technique in lieu of EPA 25A must apply for and obtain approval of an ASP.

EPA Method 18 applies to the analysis of approximately 90 percent of the total gaseous organic compounds emitted from an industrial source. It is an extremely flexible procedure and is primarily used for the measurement of emissions from sources in the synthetic organic chemical manufacturing industry. EPA Method 18 shall be the required VOC measurement technique whenever it is required by Chapter 17-296, F.A.C., or 17-297, F.A.C., or an applicable federal NSPS or NESHAP. Any owner who wants to use another measurement technique in lieu of EPA Method 18 must apply for and obtain approval of an ASP.

If the estimated concentration of VOC emissions from the exhaust of a combustion source (incinerator/afterburner) are estimated to be less than 50 ppmv as carbon, the owner may request approval to use EPA Method 25A in lieu of EPA Method 25. The request must be accompanied by the results of simultaneous EPA Method 25 and EPA Method 25A compliance tests which meet all applicable audit requirements. In order to be acceptable the tests must be conducted at 90 to 100% of the maximum permitted capacity, and the EPA Method 25 must pass the required audit, produce EPA Method 25A results that are less than 50 ppmv, and also produce EPA Method 25 results that are not greater than 75 ppmv as carbon. The use of EPA Method 25A for subsequent compliance tests may be approved through the process for alternate standards or procedures under those circumstances.

If it is deemed desirable to subtract methane from the total hydrocarbons measured by EPA Method 25A, EPA Method 18 should be required to identify and measure most (~90%) of the hydrocarbons. EPA Method 18 will determine the degree of negative bias due to partially oxidized/chlorinated organic compounds.

The approval of alternate test methods is handled by the Emissions Monitoring Section. Any questions on the ASP process should be referred to Mike Harley at SC 278-1344 or (904)488-1344.

HLR/sa/cjh

Florida Department of
Environmental Protection

Memorandum

DARM-EM-01

TO: District Air Program Administrators
County Air Program Administrators

FROM: Howard L. Rhodes, Director
Division of Air Resource Management

DATE: March 2, 1994

SUBJECT: Guidance Regarding EPA Method 25

The following applies to EPA Method 25 in Florida:

- Rules 17-297.330 and 297.310(1), F.A.C., (Florida Administrative Code) requires that three runs at least one hour in duration be conducted as a minimum for each test measuring mass emissions, except for specific situations which are covered in that section of the rule. To perform four runs for the purpose of being able to reject one of them is not acceptable. There must be a reason for rejection at the time of the run such as sample train failure, etc.

- Rule 17-297.330(1)(a), F.A.C., requires each run to be from one-to-four hours in duration. The entire test (all three runs) must be done within a consecutive five day period.

- The owner must notify the Department at least 15 days before a compliance test is conducted. If that test (usually an annual compliance test) is completed and the results show a failure to meet the applicable standard or permit conditions, the Department shall initiate appropriate enforcement action.

- If the compliance test results are inconclusive, the Department requires a retest within a short period of time, usually about 30 days.

- The use of EPA audit gases to verify the ability of the laboratory to obtain proper results is required.

- EPA has instructed the Department that the audit gas concentration is not to be revealed to the source's test team.

- Rule 17-297.620, F.A.C., can be used on a source-by-source basis to obtain approval of alternate sampling methods. The Department will review and make a determination about any proposed deviations from the test method. The applicant is responsible for demonstrating that such alternate procedures are adequate to demonstrate compliance. Such requests should be submitted to the Department at least three months before the desired test date since any major changes in the method require EPA review and approval.

If split samples are analyzed by more than one laboratory, the Department will normally consider the test inconclusive if some results indicate failure and some indicate compliance. The Department will review conflicting test results on a case-by-case basis to determine compliance. For consistency, those tests must be reviewed by the Emissions Monitoring Section in the Bureau of Air Regulation before final acceptance or rejection is determined.

Audit cylinder gases for Method 25 are available to regulatory agencies by calling Louis Nichols at Suncom 278-1344. He must be notified at least 45 days prior to the compliance test to provide enough time to have the cylinder shipped to the District or County office. The use of the audit gas is required by EPA Method 25.

HLR:cjh

Indiantown Cogeneration, L.P.

Document Control No. 3628
File No. 6.3.1

RECEIVED

MAY 24 1995

Bureau of
Air Regulation

May 19, 1995

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Winston A. Smith, Director
~~Air Pesticides and Toxic Substance Management Division~~
Region IV
Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, GA 30365

Re: Initial Firing of Main Boilers
PSD-FL-168 (Second Notice)

Dear Mr. Smith:

On April 17, 1995 Indiantown Cogeneration L.P. (ICL) notified you that the main boiler at this facility was anticipated to fire coal for the first time on or after May 22, 1995. The notification was intended to fulfill the requirements of 40 CFR 60.7(a)(2), notification of the anticipated date of initial startup not more than 60 days and not less than 30 days prior to that date. We now anticipated first fire of coal on June 19, 1995 which is more than 60 days from our original notice. ICL hereby provides a second notice of initial startup to comply with the referenced requirements.

Please call me at (301) 718-6973 if you have any questions.

Sincerely,

Michelle Griffin

Michelle Griffin
Environmental Specialist

MG/tmk

cc: Clair Fancy (FDEP)
Thomas Tittle, FDEP-WPB

7500 Old Georgetown Road • Bethesda, Maryland 20814-6161 • 301-718-6800 • Fax 301-718-6900
An affiliate of U.S. Generating Company

Our files [illegible]

Indiantown Cogeneration, L.P.

RECEIVED
FEB 6 1995
Bureau of
Air Regulation

February 3, 1995

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Winston A. Smith, Director
Air Pesticides and Toxic Substance Management Division
Region IV
Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, GA 30365

Re: Initial Firing of Auxiliary Boilers
PSD-FL-168

Dear Mr. Smith:

Indiantown Cogeneration L.P. (ICL) hereby notifies you that both auxiliary boilers were fired for the first time on January 19, 1995. The boilers were fueled with propane.

This notification fulfills the requirements of 40 CFR 60.7(a)(3), notification of the actual date of initial startup. These boilers are subject to the requirements of 40 CFR Part 60, Subpart Db.

Please call me at (301) 718-6973 if you have any questions.

Sincerely,

Michelle Griffin

Michelle Griffin
Environmental Specialist

MG/tmk

cc: Clair Fancy, FDEP
Thomas Tittle, FDEP-WPB

Joly 10/19
BM 10/21/94

Indiantown Cogeneration, L.P.

October 17, 1994

Mr. Winston A. Smith, Director
Air Pesticides and Toxic Substance Management Division
Region IV
United States Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, Georgia 30365

RECEIVED
OCT 18 1994
Bureau of Air Regulation

File #: 66.7.2

RE: Anticipated Date of Initial Startup of Two Auxiliary Boilers

Dear Mr. Smith:

As required by 40 CFR 60.7(a)(2), we are pleased to notify your office that the anticipated date of initial startup of the two natural gas or propane-fired boilers at the Indiantown Cogeneration Project near Indiantown, Florida is November 16, 1994.

These boilers are subject to the requirements of 40 CFR Part 60, Subpart Db. Should you or your staff have questions, please contact me at (301) 718-6937.

Sincerely,

Barrett Parker

Barrett Parker
Environmental Specialist

cc: Clair Fancy, FDEP
Thomas Tittle, FDEP

Patty - for file
copy district

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

OCT 12 1994

4APT-AEB

RECEIVED
OCT 17 1994
Bureau of
Air Regulation

Mr. Clair Fancy
Chief
Bureau of Air Regulation
Air Resources Management Division
Florida Department of Environmental
Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: SO_2 Monitoring Alternative Proposed for Indiantown Cogeneration, L.P (ICLP), Indiantown, Florida

Dear Mr. Fancy:

The purpose of this letter is to provide you with comments on the referenced alternative that was sent jointly to the U.S. Environmental Protection Agency (EPA) Region IV and the Florida Department of Environmental Regulation on August 2, 1994. The boiler at ICLP will be subject to 40 C.F.R. Part 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978), and comments are being provided to you since authority to implement Subpart Da has been delegated to your agency. After reviewing the proposed alternative, it has been determined that it is not acceptable because provisions in it are less stringent than those in a similar proposal that was approved for a source in EPA Region II earlier this year.

The boiler at ICLP is subject to a 70 percent SO_2 removal efficiency requirement under Subpart Da, and the proposed alternative involves the method used to calculate the control device removal efficiency. According to 40 C.F.R. §60.47a(b), SO_2 removal efficiency is determined by measuring the SO_2 emission rate at the inlet and outlet of the control device. Under these provisions, emission rates at the outlet of the control device are measured with a continuous emission monitor (CEM), and emission rates at the inlet to the control device are measured with either a CEM or with fuel sampling and analysis. Compliance is determined continuously on a 30-day rolling average basis.

ICLP is seeking approval for an alternative SO_2 removal efficiency measurement procedure because the SO_2 emission limit for the boiler and the design of the boiler control system will result in an SO_2 removal efficiency much higher than that required in Subpart Db. Under the alternative proposed by ICLP, the SO_2 emission rate at the inlet to the control device would be determined with either EPA Method 6B or EPA Method 19 for the initial 30-day compliance test. Following the initial compliance test, coal supplier information on sulfur content would be used to determine the SO_2 emission rate at the control device inlet. The proposal also contains provisions for analyzing coal samples on a semi-annual basis as a quality assurance check on coal supplier data and revocation of the alternative if the demonstrated efficiency of the control device ever drops below 80 percent on a 30-day rolling average basis.

After reviewing the ICLP proposal, and a similar proposal that was approved for Chambers Cogeneration Limited Partnership (CCLP) in Carneys Point, New Jersey, it has been determined that the ICLP alternative cannot be approved because it is less stringent that the alternative approved for CCLP. Concerns regarding the stringency of the ICLP proposal involve two primary areas--the frequency of independent testing used to supplement coal supplier sulfur analyses and the procedures used to calculate control device efficiency.

The quarterly QA testing used to verify coal supplier analyses under the ICLP proposal is not adequate because it involves less frequent testing than the approved CCLP alternative. Under the CCLP alternative, the company must use EPA Method 19 analysis of as-fired coal samples, EPA Method 6B, or a CEM to measure the SO_2 emission rate at the control device inlet on the first operating day of each month. Therefore, in order to be approved, the ICLP alternative must include monthly testing to supplement sulfur content information provided by coal suppliers.

A second concern regarding the ICLP proposal involves a major difference between how SO_2 removal efficiency is calculated under the ICLP and CCLP alternatives. Under the ICLP alternative, the SO_2 removal efficiency following the initial compliance test would be determined based upon inlet emission rates calculated from coal supplier data and outlet emission rates measured with a CEM. Under the approved alternative for CCLP, SO_2 removal efficiency is calculated from the lowest inlet emission rate ever measured by any of four methods (SO_2 CEM, analysis of as-fired coal samples, EPA Method 6B, or coal supplier data) and outlet emission rates measured with a CEM.

The CCLP method for calculating control device efficiency is more conservative than the approach proposed by ICLP, since the CCLP alternative uses the lowest inlet emission rate ever measured in the efficiency calculations. The conservatism of CCLP approach, however, is considered fundamental to its acceptance. The review of the CCLP alternative had to be coordinated with several EPA program offices, and some offices were opposed to its acceptance. Because of the opposition that some offices had to the CCLP alternative, it could not have been approved if it had used a less conservative approach for calculating SO_2 removal efficiencies. Therefore, the ICLP proposal cannot be approved unless it uses SO_2 removal efficiency calculation procedures that are at least as conservative as those in the CCLP alternative.

In summary, the ICLP alternative monitoring procedure cannot be approved as it is currently drafted. If ICLP revises the proposal in response to the comments in this letter, a copy of the revised proposal should be provided to EPA for review.

If you have any questions about the determination provided in this letter, please contact Mr. David McNeal of my staff at 404/347-3555, voice mailbox 4158.

Sincerely yours,

Jewell A. Harper
Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division

cc: Mr. Michael Harley, Florida DEP
Mr. Martin Costello, Florida DEP

Ms. Michelle Griffin
Indiantown Cogeneration L.P.
U.S. Generating Company
7500 Old Georgetown Road
Bethesda, Maryland 20814-6161

Florida Department of
Environmental Protection

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

September 16, 1994

Michelle Griffin
Indiantown Cogeneration, L.P.
7500 Old Georgetown Road
Bethesda, Maryland 20814-6161

RE: Proposed Amendments to PSD-FL-168, Emission Limits/Stack Height Increase

Dear Ms Griffin:

Your letter dated August 25, 1994 requested changing the PSD permit emission limits to conform to the limitations in the Site Certification. We have determined the cause for the inconsistency in fluoride emission limits between the Site Certification and the PSD permit. In volume 2, page 5.6.1-11 of your Site Certification application, you list the maximum hourly emission rate for fluorides as 5.08 lbs/hr. Then, in your April 1, 1991 submittal of sufficiency responses, volume 1 page FDER-40, the emission rate is listed as 7.26 lbs/hr, although the TPY value is listed as 22.26 in both documents. Since your company provided the Department with both emission rates, please inform the Department which emission rate is correct.

The emission limit differences are small for all but the fluoride limits. The Site Certification value (7.26 Lbs/hr) is 42% higher than the PSD limit (5.08 Lbs/hr). The TPY limits for Fluorides are not significantly different. When you divide the TPY limits (22.26) by 8760 hrs/yr the answer is 5.08 lbs/hr. The Bureau of Air Regulation's Technical Evaluation and Preliminary Determination was based on an emission rate of 5.08 lbs/hr for fluorides. Industrial Source Complex modeling results based on 5.08 Lbs/hr showed fluoride concentrations would be two orders of magnitude less than the "no-threat" levels. Changing the fluoride limit to 7.26 lbs/hr should not change these modeling results. Since the Technical Evaluation was based on the emission rates established in the PSD permit these should remain unless there are good technical reasons to change them. I recommend that you withdraw your request to amend the PSD permit and submit a request to change the Siting Certification emission limits to conform to the values in the PSD permit. If the main boiler is not capable of meeting the lower limit for fluoride, you should inform the Bureau of Air Regulation of this fact and provide the reasons why as well as a technical evaluation of the impacts associated with the increased fluoride emissions.

Tom Rogers, DEP Office of Policy Analysis and Program Management, has determined that the increase in height for the auxiliary boilers stack will not cause additional adverse air quality impacts. No changes to the text of the PSD permit will be needed for this change.

If you have questions on any of these items, please contact Martin Costello (904) 488-1344.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

cc: Martin Costello

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SEP 19 1994

Bureau of
Air Regulation

Mady c. Nagle

Indiantown Cogeneration, L.P.

August 9, 1994

RECEIVED

AUG 15 1994

Bureau of
Air Regulation

Mr. Hamilton S. Oven, Jr.
Administrator, Office of Siting Coordination
Department of Environmental Protection
3900 Commonwealth Blvd., MS 48
Tallahassee, FL 32399-3000

Dear Mr. Oven:

As required by Condition of Certification II (1.)A.2(c), this letter transmits the eighth quarterly report for the Indiantown Cogeneration Project for the period ending June 30, 1994. I have enclosed a color photo copy of an aerial photo of the site illustrating progress as of July 1994.

During the second quarter of 1994, construction was focused on erection of the boiler, air preheater and baghouse building structural steel as well as the installation of the mechanical and electrical bulk commodities in the boiler and turbine buildings. Hydrostatic testing of the raw water pipeline was successfully accomplished and the pipeline is completed. The intake structure at Taylor Creek/Nubbin Slough has essentially been completed; the intake screens were installed in May. Other construction accomplishments during this period include the start of construction of the Spray Dryer Absorbers, he erection of the cooling tower and foundation construction for installation of the boiler induced draft (ID) fans. Erection of the turbine generator has commenced upon receipt from GE of the major casings and rotating assemblies for the turbine. The last major component, the generator, is expected to arrive on-site in the next quarter. Boiler erection continues with major emphasis on the installation of superheater and reheater tube assemblies and continued erection of water well tubes.

The sanitary system has been accepted by the Southeast District office of FDEP, completing the permit process for that system. Release of the potable water system by FDEP is anticipated early in the third quarter. The ambient air monitoring system was approved and monitoring initiated in May, one year prior to the anticipated firing of coal in the boiler. The Visitor Center has been relocated to an area adjacent to the plant administration building.

Engineering for the project is approximately 78% complete. Civil and mechanical engineering are essentially complete with on-going efforts related to the preparation of system descriptions and vendor drawing reviews. Instrumentation engineering has focused on the factory testing of the plant DCS system and preparation of operating programs and software for the system. Electrical engineering has continued with the design conduit, cable routing and electrical connection drawings for the project. Design engineering has completed most small bore piping design and continues to complete large and small bore piping supports.

Major vendors continue to provide regular shipments of materials to the site. Foster Wheeler continues to supply boiler components to support erection activities. General Electric initiated delivery of turbine-generator components including the high pressure and low pressure motors. Procurement activities for most components are now complete, with emphasis being placed on expediting deliveries to the site. The plant continues emission monitoring (CEM) system was awarded this quarter to Enviroplan. CEM system design details will be forwarded during the next quarter.

As of June 30, 1994, 76 non manual employees and 656 direct hire craftsmen are employed at the site. We continue to provide environmental awareness training to all on-site personnel as they join the project.

You are welcome to come visit the site to review progress first hand. If you would like to schedule a visit or if you have any questions, please call me at (301) 718-6973.

Sincerely,

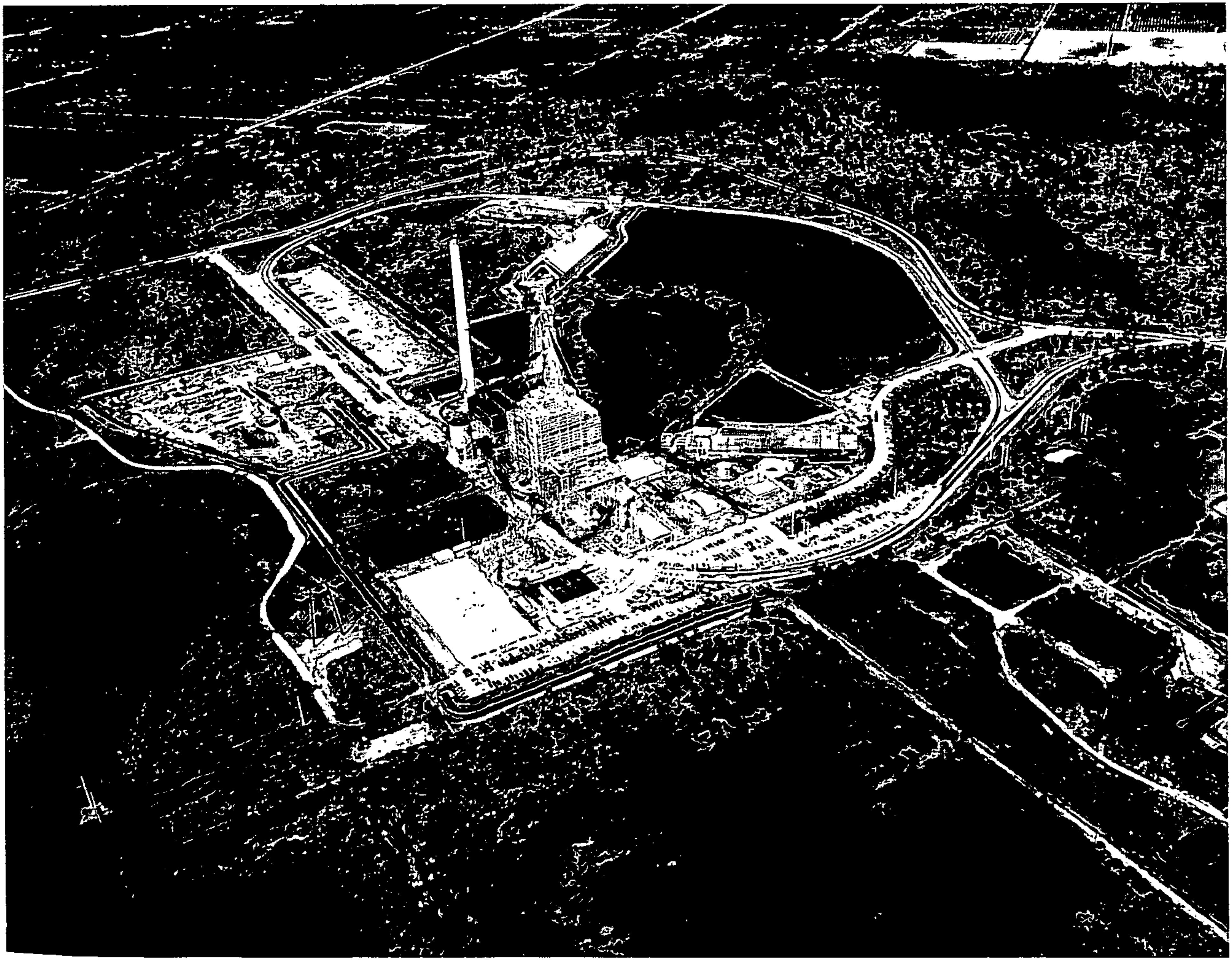
Michelle Griffin

Michelle Griffin
Environmental Compliance Specialist

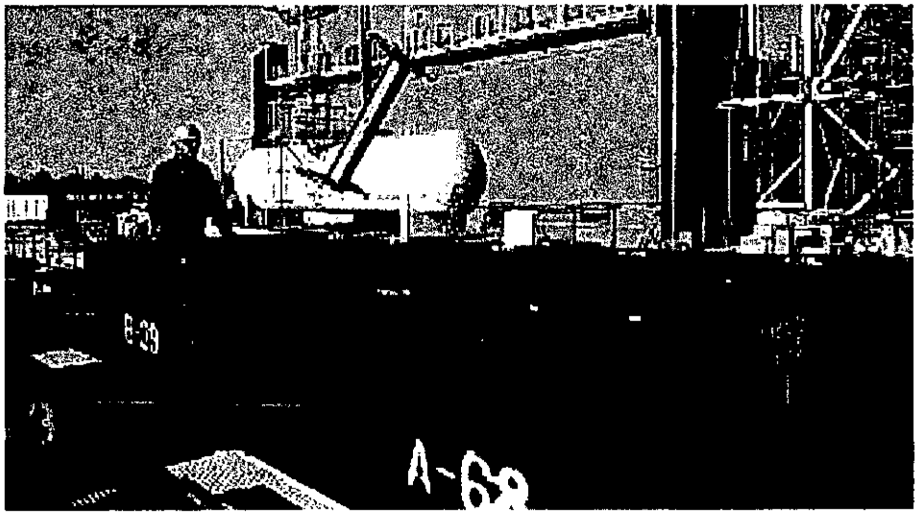
Enclosure: 1 photo

cc: Preston Lewis, w/photo
Richard Donelan, w/photo
Susan Coughanour, w/photo
G. Harper, EPA
I. Goldman, SEOIC.

bcc: B. Applewhite, w/enclosures
S. Sorrentino
C. Allen
M. Surabian
P. Carr
C. Carlton
B. Mourer
T. Keller
V. Ibrahim, w/enclosures
B. Parker
MGChron File
MG Quarterly Reports



First Ammonia-Based Selective



Workman prepares to attach the catalyst unit to the catalyst basket which will be used to lift the catalyst unit into place.

Carneys Point SCR System Description

An overall arrangement of the Carneys Point steam generator with its SCR unit is shown in the Figure 1 schematic. The SCR unit, which is placed between the economizer and the air heater, consists of a partial economizer bypass duct, an ammonia injection grid, flow-turning vanes, a flow rectifier, an SCR reactor or catalyst layers, steam sootblowers, and associated ducting. The flue-gas conditions at the SCR inlet and outlet are presented in Table 1 (Pg. 5).

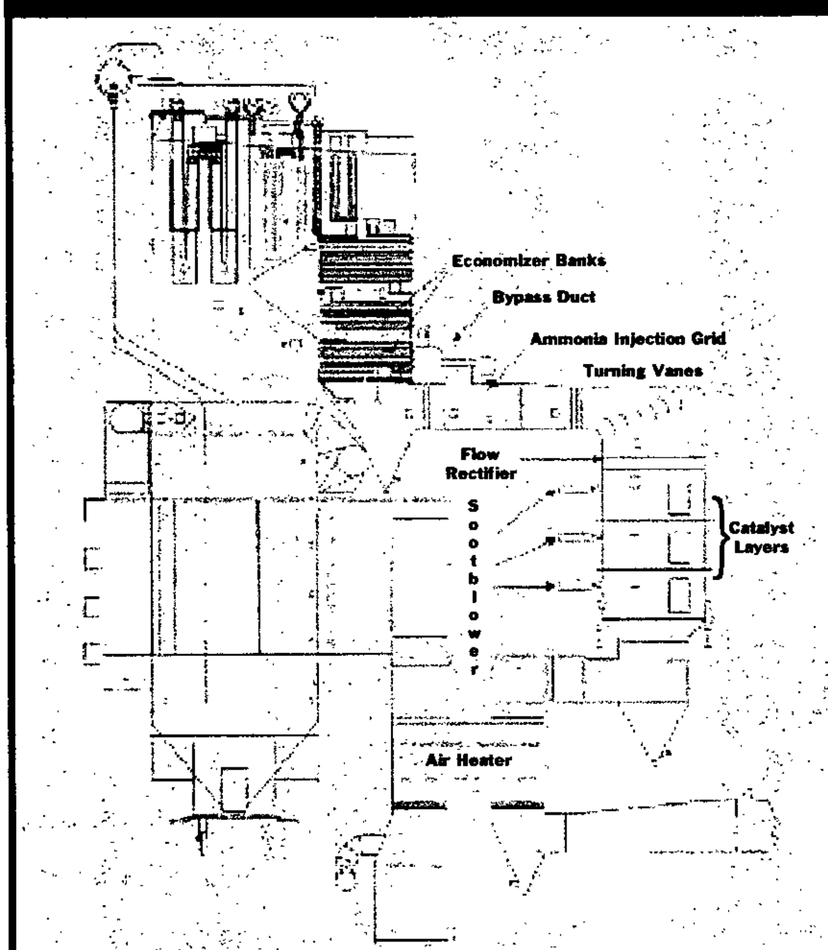
Economizer Bypass Duct: The steam generator burns a 2%- sulfur coal, producing SO_2 and a small quantity of SO_3. A small fraction of SO_2 in the flue gas is also converted to SO_3 in the SCR reactor.

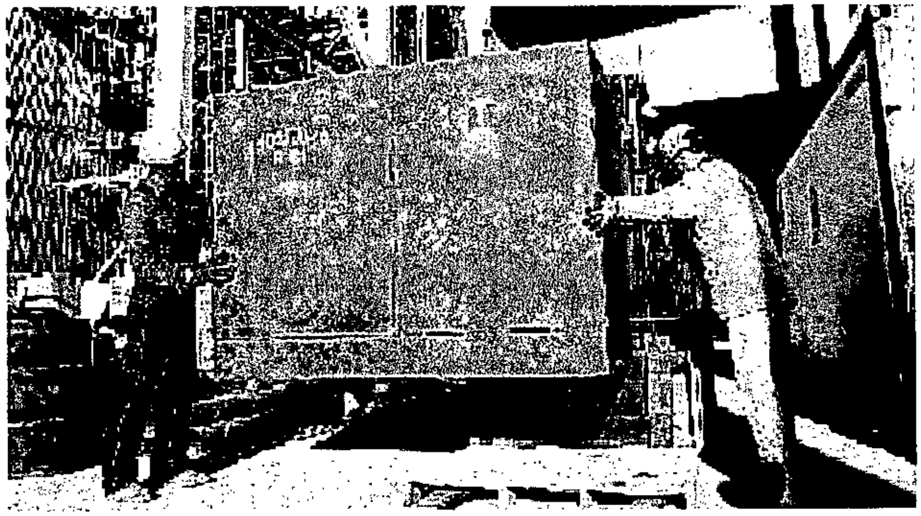
When combined with ammonia and water vapor, SO_3 may form ammonium sulfate/bisulfate and this probability increases with decreasing flue-gas temperature. When the plant load decreases from full load operation, the flue-gas temperature leaving the economizer also decreases. Consequently, there is a potential, in the range of 35% to 50% of full load, for the formation of ammonium sulfate/bisulfate in the catalyst. Therefore, for operation at 35%-to-50% full load, part of the flue gas is bypassed around a portion of the economizer to maintain the flue-gas temperature above approximately 610°F. This is the minimum gas temperature for the Carneys Point conditions below which ammonium sulfate/bisulfate could be formed in the catalyst.

A damper in the bypass duct and a damper at the economizer outlet duct are, in unison, automatically temperature-controlled between 610°F and 710°F to open or close the bypass flow. It may also be noted that the ammonia slip downstream of the SCR reactor is kept at very low values to help protect the downstream equipment from the effects of possible formation of ammonium sulfate/bisulfate.

Ammonia Injection Grid: The injection of the ammonia gas (in a carrier air stream) into the flue-gas stream is made

Figure 1: Overall arrangement of Carneys Point steam generator and SCR unit





Installers move a catalyst element into position before it is hoisted into the reactor unit. The catalyst was specifically designed for the type of coal burned at the plant.

via a network of injection pipes. The injection plane is divided into 12 zones which are individually controllable in either the horizontal or vertical plane.

Each zone is fed with ammonia through a common supply manifold and controlled using a flow meter and a control valve. Individual injection pipes, branching from the common supply manifold, contain circular injection holes on the side of the pipe for ammonia injection into the flue gas. During initial operation, these zones were fine-tuned to provide a proper distribution of the ammonia flow which is compatible with the flue-gas and NO_x distributions across the SCR duct.

Turning Vanes: A set of turning vanes is installed at the 90-degree duct bend to provide good flow distribution while minimizing gas-side pressure drop. The exact locations, number and geometric shapes of these vanes were determined based on the results of a scale model flow test.

Flow Rectifier: Because of high dust loading associated with coal firing, the linear velocity of the gas stream is limited to approximately 20 ft/sec for catalyst erosion consideration, and the gas flow entering the catalyst layer is straightened by a flow rectifier made of square tubes. The inlet velocity vector that is in line with the catalyst flow path decreases the erosion potential and this is accomplished with the use of the flow rectifier.

Catalyst Reactor: The Carneys Point SCR catalyst is supplied by Ishikawajima-Harima Heavy Industries Company (IHI) of Japan. It is the homogeneous honeycomb type that is made entirely of extruded ceramic material. The major components of the catalyst are vanadium pentoxide (V_2O_5), titanium dioxide (TiO_2) and tungsten trioxide (WO_3).

The catalyst is specifically designed for the type of coal burned at this plant. Design considerations for the catalyst pitch to prevent plugging, strength of the material to prevent erosion, and a low SO_2-to-SO_3 conversion rate to prevent the formation of ammonium sulfate/bisulfate played an important role in the catalyst design.

The SCR reactor can accommodate three separate layers of catalyst. Initially, the top two layers are loaded with catalyst, with the third layer reserved for a spare charge, if required, to meet the denitrification performance for the first ten-year period of operation.

Sootblowers: Sootblowers are installed upstream of the catalyst layers and are utilized to re-entrain the dust particles into the flue-gas stream using superheated dry steam. The sootblowers are sequentially

(continued on page 6)

Table 1: Carneys Point SCR Conditions

Flue-Gas Flow Rate per Unit	1,350,000 lb/hr
Flue-Gas Temperature	740 °F
Sulfur Content in Performance Coal	2.0%
NO_x Level at SCR Outlet	Not greater than 0.17 lb/MM Btu
Reagent	Aqueous Ammonia (27% Ammonia Content)
Ammonia Slip at SCR Outlet	5 ppmvd at 7% O_2
Operating Load Range	35 to 100% MCR
Catalyst Warranty Period	10 Years

Catalyst elements were hoisted individually to the reactor unit placed between the economizer and the air heater. Foster Wheeler selected a homogeneous honeycomb catalyst made entirely of extruded ceramic material for the installation.

operated from top to bottom of the successive layers, thereby reducing the steam consumption rate.

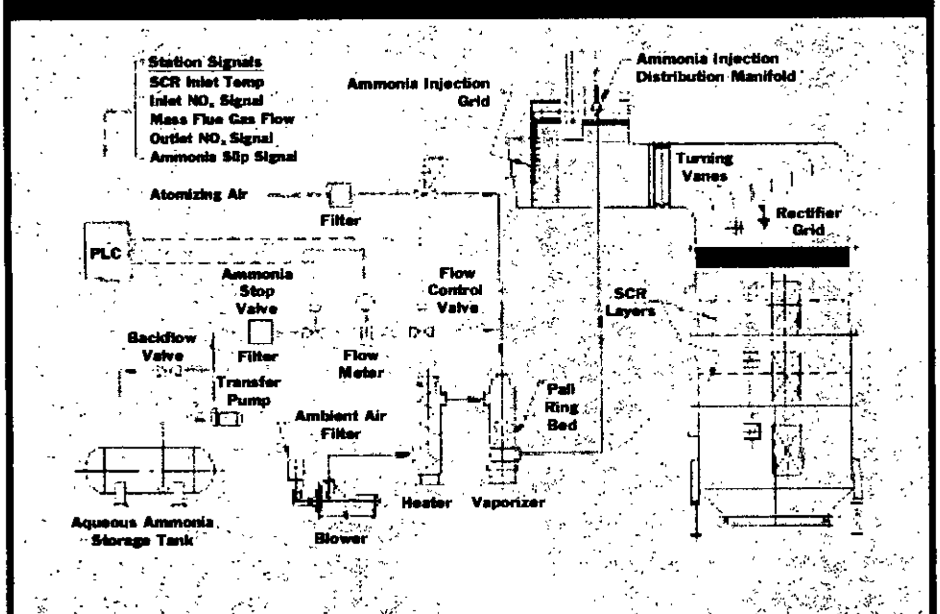
(Details of the Carneys Point SCR design were reported in "Design of a Selective Catalytic Reduction System for NO_x Abatement in a Coal-Fired Cogeneration Plant" by S.M. Cho and S.Z. Dubow, which appeared on pages 717-722 of the 1992 Proceedings of the American Power Conference.)

Ammonia System and Flow Control

The Carneys Point Generating Plant employs two steam generators, each with its own SCR unit that uses aqueous ammonia with an ammonia content of approximately 27%. The ammonia system is comprised of two 100%-capacity vaporization/dilution trains serving each steam generator independently. A third 100%-capacity redundant train, which is common to both steam generators, is available for use during maintenance or system upsets.

Aqueous ammonia that is stored in a tank is pumped, metered and sprayed, via air-atomizing nozzles, into the vaporizer (Figure 2). Ambient air, drawn by a blower, is heated by an electric heater and enters the same vaporizer. In the vaporizer, aqueous ammonia mixes with hot air and is vaporized. The resultant vapor mixture from the vaporizer is routed to the injection grid via a distribution manifold system.

Figure 2: Ammonia Injection System for Carneys Point SCR System



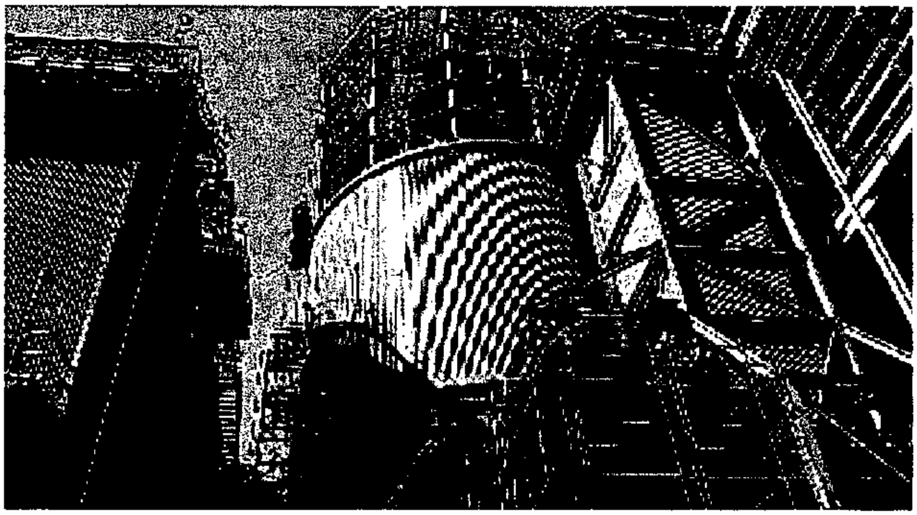
The ammonia-injection process is regulated by the plant's distributed control system (DCS). The DCS regulates a flow-control valve which adjusts the aqueous ammonia flow rate. The control scheme utilizes a feed-forward/feed-back control algorithm. The base ammonia injection rate is set by a feed-forward signal representing inlet NO_x load and flue-gas temperature. Fine tuning of the ammonia injection rate was accomplished via a feed-back signal coming from SCR outlet NO_x concentration and ammonia slip measurements.

A programmable controller automatically regulates the crossover between the dedicated vaporizer train and the standby redundant vaporizer train. Process control is maintained utilizing inlet NO_x continuous emission monitoring (CEM) analyzers, outlet CEM analyzers for NO_x and O_2, a differential pressure transmitter across the SCR reactor, and a three-point thermocouple grid at the SCR inlet.

Operating Experience

The construction of the Carneys Point Generating Plant was completed in the fourth quarter of 1993, followed by prestart-up activities including steam blowing. The upper two layers of the catalyst were loaded in October 1993 and the ammonia system checkout was

(continued on page 8)



The SCR reactor (right) is shown loaded with two layers of catalyst. If required, a third layer of catalyst may be added during the first 10 years of operation to meet denitrification performance.

conducted. First coal firing was done in December 1993 and first electricity supply to Atlantic Electric Company took place in early January 1994. Commercial operation began officially the week of March 13, 1994, and the final 100-hour acceptance tests were successfully completed in May 1994.

In order to monitor the denitrification performance of the SCR unit, an array of sampling points were strategically located throughout the SCR system as described below. At the SCR inlet prior to the ammonia injection grid, a 12-point array monitored $NO_x/O_2/CO$ levels, temperature, and flow velocity at locations which directly correspond to the 12 ammonia injection zones. These data were used to set the initial adjustments of the ammonia balancing system.

At the SCR outlet, a 36-point array monitored NO_x, O_2, and NH_3 levels at locations which directly correspond to the center of each catalyst module. These data were utilized for the fine-tuning adjustments made to the ammonia injection zones.

Table 2 and Table 3 (Pg. 9) present the actual SCR operating data taken during the final 100-hour acceptance tests at 100% MCR load for Boiler Units No. 1 and No. 2, respectively. From these tables, the following observations were made:

1) All the data points lie below the specified NO_x emission rate of 0.17 lb/MMBtu or 99 ppmvd, with less than 5 ppmvd of ammonia slip, thus meeting the air permit's emission criteria.

2) Data No. 6 and Data No. 12 indicate that the NO_x emission rate reached as low as 0.1 lb/MMBtu, or approximately 57 ppmvd.

3) The design ammonia slip at the SCR outlet is 5 ppmvd, but actual operating data show extremely low values on the order of 0.26 ppmvd or less. This is indicative of the SCR performance far exceeding the design conditions. (An independent verification of the SCR denitrification performance was conducted by an environmental testing laboratory. This analysis confirmed that the SCR performance exceeded the design criteria as indicated by the extremely low values for the ammonia slip.)

During the test period, the ammonia slip remained extremely low and at approximately a constant level.

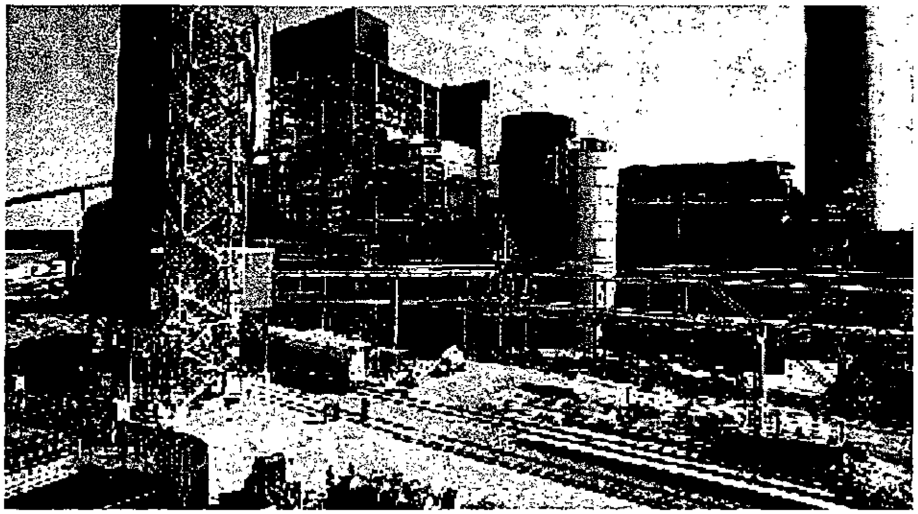
Table 2: Carneys Point SCR Operating Data — Boiler Unit No. 1

Data No.	1	2	3	4	5	6	7
Date	5/18/94	5/19/94	5/20/94	5/21/94	5/22/94	5/23/94	5/24/94
Boiler Load % of MCR	100	100	100	100	100	100	100
Flue-Gas Flow, MMlb/hr	1.36	1.37	1.34	1.32	1.32	1.38	1.39
Gas Temp. at SCR °F	709	700	690	707	707	701	709
Outlet NO_x** – lb/MMBtu	0.128	0.130	0.153	0.122	0.110	0.098	0.128
Outlet NO_x** – ppmvd*	64.6	71.8	90.1	69.4	62.7	55.8	71.8
Ammonia Slip**, ppmvd*	0.255	0.264	0.262	0.245	0.237	0.227	0.047
SCR Pressure Drop***, Inches of H_2O	2.54	2.48	2.44	2.20	2.42	2.59	2.58

* Referenced at 7% O_2 Level

**Air Permit Limits: Outlet NO_x = 0.17 lb/MMBtu or 99 ppmvd
Ammonia Slip = 5.0 ppmvd at 7% O_2

***With 2 layers of catalyst. Design limit is 4 inches of H_2O with 3 layers of catalyst



The Carneys Point pulverized-coal cogeneration plant (shown here during the construction phase) was the first plant of its kind in the U. S. to employ an ammonia-based SCR system. Foster Wheeler's pioneering work in design and installation of the system helped limit the stack NO_x to 0.17 lb/10^6 Btu.

Post-test inspections revealed no fouling, plugging or poisoning of the catalyst, and no adverse effects on the downstream components. The latter may be attributed to the extremely low levels of ammonia slip obtained by the SCR system.

4) The flue-gas pressure drop through the SCR system is also shown in the tables. With the two layers of catalyst loaded at the present time, the gas pressure drop is in the range of 2.20 to 2.70 inches of water for the gas flow range of 1.32 to 1.42 million lb/hr as shown. The corresponding predicted pressure drop is in the range of 2.60 to 2.81 inches of water for the specified gas conditions. This comparison indicates that the actual pressure drop is less than the prediction by approximately 10% on the average.

The ammonia slip tends to increase with time as the NO_x-removal capability of catalyst tends to decrease with time. The current catalyst management strategy is the addition of catalyst in the third layer of the SCR reactor when the ammonia slip reaches the air permit's limit value of 5 ppmvd referenced at 7% O_2.

To this end, several catalyst sampling cells were installed in the reactor and these cells can be removed from the reactor at regular intervals in order to assess the conditions of the catalyst at any given point in time, thereby helping in the planning of catalyst management strategy. Testing activities also include denitrification activity test, SO_2-to-SO_3 conversion test, and crushing strength test.

Summary and Conclusions

The Carneys Point Generating Plant is the first U.S. pulverized-coal-fired steam generating plant equipped with ammonia-based SCR units. The plant was started up in late 1993 and the final acceptance tests were completed in May 1994.

SCR operating data to date reveal that the NO_x emission rate has met the air permit's limit value (0.17 lb/MMBtu), and reached as low a value as 0.1 lb/MMBtu, with low ammonia-slip values on the order of 0.26 ppmvd. The gas-side pressure drop has also been within the specified design-limit value. ■

Acknowledgment

The authors would like to thank the members of the Carneys Point Project Team at U.S. Generating Company, Bechtel Corporation and Foster Wheeler Energy Corporation for their cooperation in the preparation of this report.

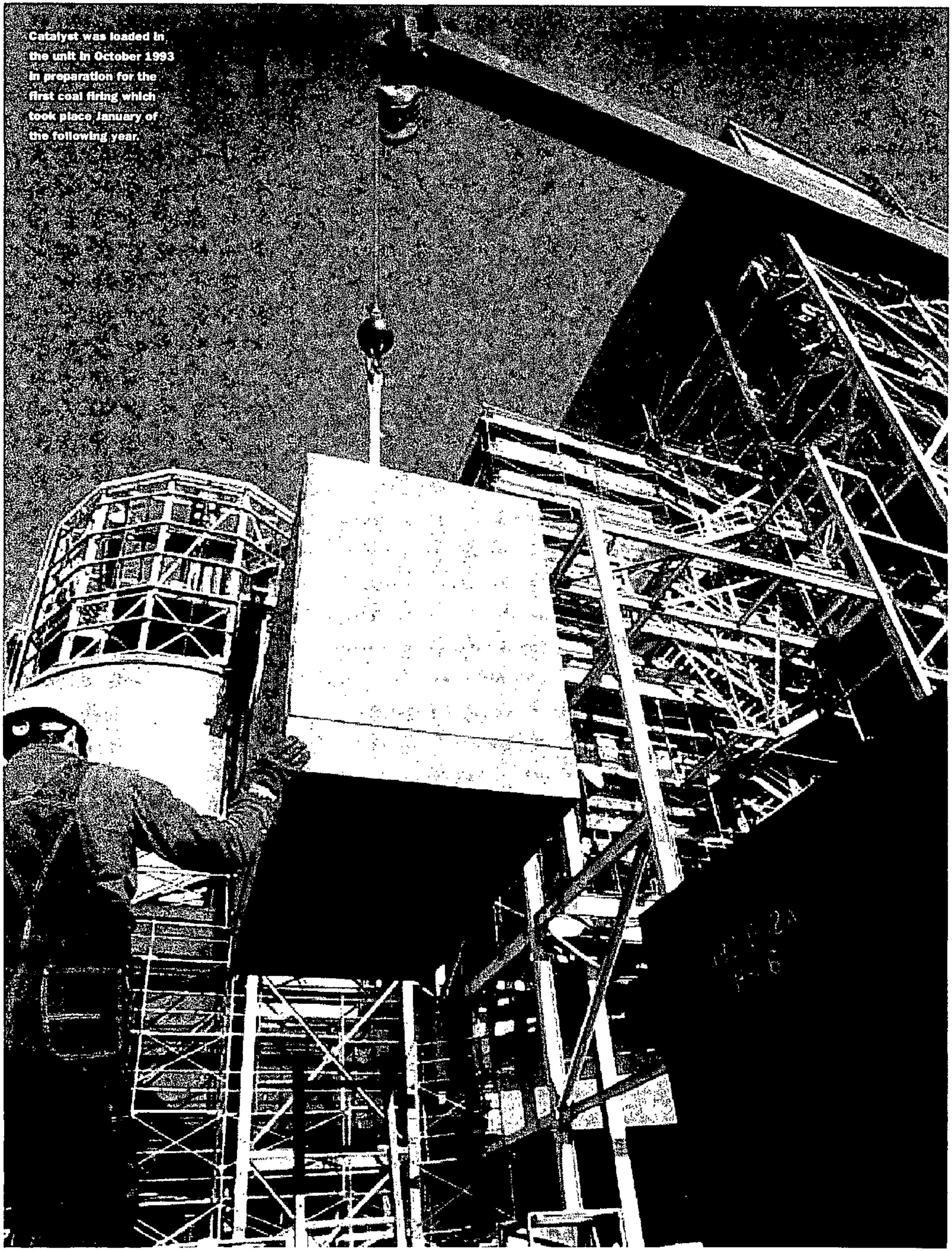
Table 3: Carneys Point Operating Data — Boiler Unit No. 2

Data No.	8	9	10	11	12	13
Date	5/18/94	5/19/94	5/20/94	5/22/94	5/23/94	5/24/94
Boiler Load % of MCR	100	100	100	100	100	100
Flue-Gas Flow, MMlb/hr	1.36	1.37	1.37	1.36	1.33	1.42
Gas Temp. at SCR, °F	721	709	706	718	708	714
Outlet NO_x** – lb/MMBtu – ppmvd*	0.138 73.4	0.127 72.2	0.120 68.3	0.111 61.4	0.105 59.9	0.136 74.5
Ammonia Slip**, ppmvd*	0.182	0.170	0.170	0.180	0.200	0.010
SCR Pressure Drop***, inches of H_2O	2.67	2.57	2.63	2.70	2.46	2.70

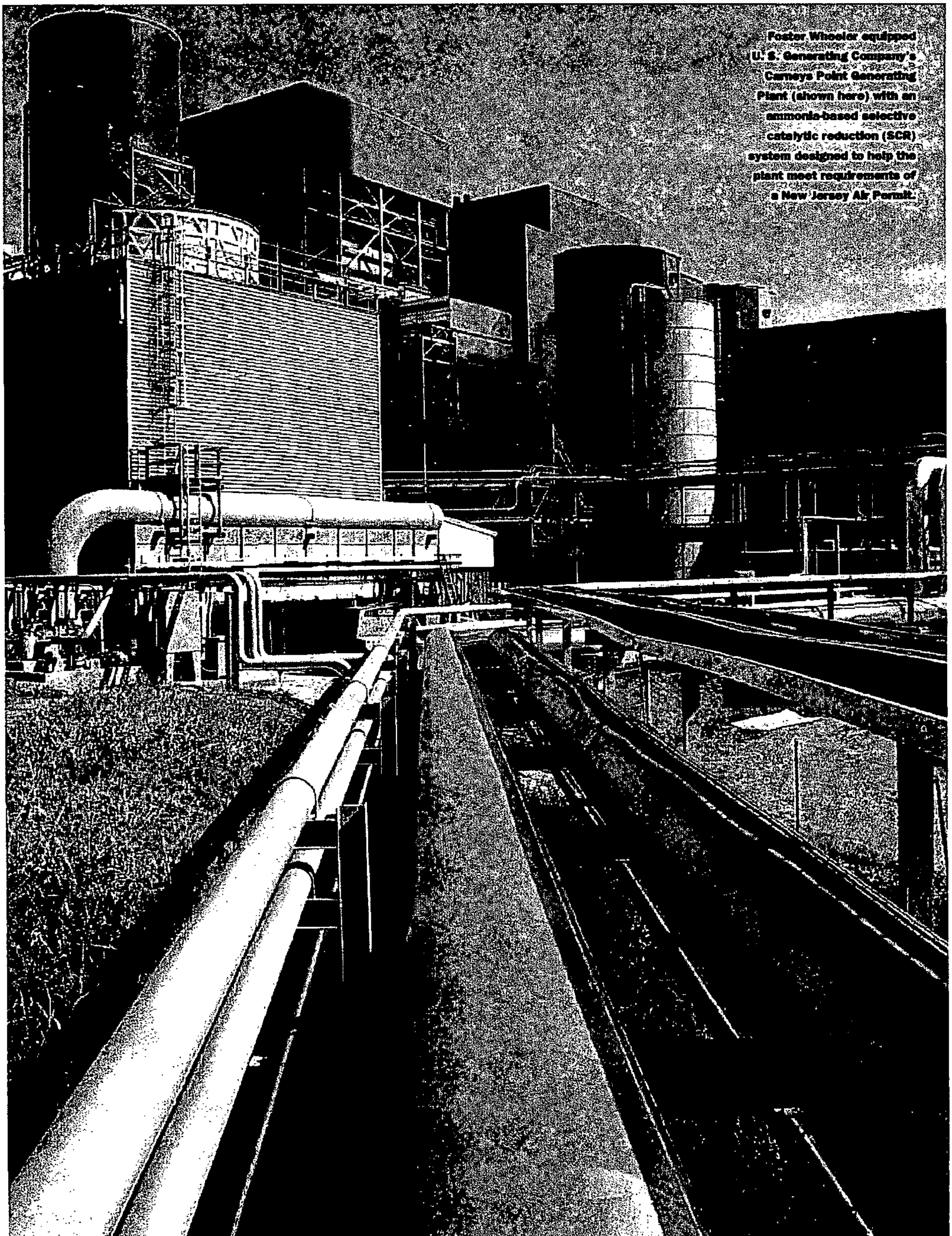
* Referenced at 7% O_2 Level

**Air Permit Limits: Outlet NO_x = 0.17 lb/MMBtu or 99 ppmvd
Ammonia Slip = 5.0 ppmvd at 7% O_2

***With 2 layers of catalyst. Design limit is 4 inches of H_2O with 3 layers of catalyst



Catalyst was loaded in the unit in October 1993 in preparation for the first coal firing which took place January of the following year.



Foster Wheeler equipped U. S. Generating Company's Carneys Point Generating Plant (shown here) with an ammonia-based selective catalytic reduction (SCR) system designed to help the plant meet requirements of a New Jersey Air Permit.