Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

June 17, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E.
KBN Engineering & Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

Re: Amendment of Construction Permit
Orlando CoGen (I), Inc.
AC48-206720; PSD-FL-184

Dear Mr. Kosky:

The Department has received EPA's response for the proposed amendment of the permit for the above referenced source. Enclosed for your review is EPA's June 3, 1994, letter on this subject.

Based on EPA's assessment of the request for the permit amendment, the Department has decided to provide Orlando CoGen (I), Inc., with the opportunity to withdraw the amendment request. If the Department does not receive the request to withdraw by July 8, 1994, then an Intent to Deny the request for permit amendment will be issued.

Please note that in the future, requests for approval of alternate standards and procedures should be directly addressed to Mike Harley of the Emissions Monitoring Section, instead of submitting them as permit amendment requests.

If there are any questions on the above, please call Syed Arif at (904) 488-1344, or write to me at the letterhead address.

Sincerely,

John C. Brown, Jr.

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JCB/sa

Enclosure

cc: J. Campbell, EPCHC
E. Curran, Cargill
M. Harper, EPA
M. Harley, BAR
B. Thomas, SWD

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Mr. Kennard F. Kosky, P.E.
KBN Engineering & Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

4a. Article Number
P 872 562 720

4b. Service Type
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7. Date of Delivery
6-22

Mary Reinert
5. Signature (Addressee)

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6. Signature (Agent)

PS Form **3811**, December 1991 ★U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

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Return Receipt Showing to Whom, Date, and Addressee's Address	
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Postmark or Date Mailed: 6/20/94 AC 48-206720; PSD-FL-184	

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

JUN 0 3 1994

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JUN 06 1994

Bureau of
Air Regulation

4APT-AEB

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

SUBJECT: Construction Permit Amendment for Orlando CoGen Limited, L.P.

Dear Mr. Fancy:

This letter is in response to your March 1, 1994, request for clarification regarding the U.S. Environmental Protection Agency (EPA) position on a permit amendment and alternative NO_x compliance demonstration procedure proposed for a gas turbine and a duct burner in a combined cycle system operated by the referenced company. After reviewing the proposed permit amendment and alternative testing procedure, we have determined that we would be opposed to approval of either proposal.

Because of concerns about the difficulty associated with testing the duct burners in the combined cycle system at Orlando CoGen, KBN Engineering and Applied Sciences, Inc. (KBN) proposed revisions to NO_x emission limits and compliance testing procedures for the combined cycle system. The emission standard revision involved establishing two emission limits--a gas turbine emission limit and a combined limit for the gas turbine and duct burner operating together. Under this proposal, there would not be a separate limit for the duct burners, and the basis for this proposal was that the duct burners will never be operated alone.

After considering the KBN proposal for emission standard revisions, we have determined that it is not acceptable because one of the applicable regulations for the duct burners, 40 C.F.R. Part 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), contains a separate NO_x emission standard for duct burners in combined cycle systems. Since Subpart Db contains a NO_x emission limit specifically for duct burners, establishing a combined NO_x emission limit for the gas turbine and duct burner would not relieve Orlando CoGen of the obligation to demonstrate compliance with the applicable duct burner NO_x emission limit in Subpart Db.

The second proposal in the request from KBN involves compliance demonstration procedures for the duct burner. According to Subpart Db, the NO_x emission rate for duct burners is determined by measuring the emission rate at both the inlet and outlet of the duct burner. As an alternative to performing the test in accordance with Subpart Db, KBN proposed to determine the duct burner emission rate by performing all testing downstream of the duct burner and operating the combined cycle systems in two modes--one with only the turbine running and one with both the turbine and the duct burner operating. Under this scenario, the duct burner emission rate would be calculated by subtracting the turbine emission rate from the emission rate with both facilities operating. In support of this proposed alternative, KBN referenced a previous approval of similar procedures for combined cycle testing that was conducted at the Florida Power and Light (FP&L) Putnam Plant.

After considering the testing alternative proposed by KBN, we do not believe that it should be approved either. The basis for this position is that we are aware of other sources where similar procedures have yielded suspect results (i.e., NO_x mass emission rates with the gas turbine and duct burner operating together were lower than they were with only the turbine operating). The reason for these suspect results is uncertain, but they may have been caused by the inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.

Although procedures similar to those proposed by KBN were approved for the FP&L Putnam Plant, we do not consider this prior approval relevant with respect to Orlando CoGen because of differences in the two facilities. The primary justification for approving alternative testing procedures at the Putnam Plant was that these units were existing units that became subject to Subpart Db due to reconstruction. Although 40 C.F.R. §60.8(e) requires that a source owner or operator provide adequate testing and sampling locations, we did not necessarily consider these requirements applicable to FP&L since the Putnam units were not subject to Subpart Db at the time the units were originally constructed. Since the combined cycle system at Orlando CoGen is new, testing requirements should have been considered during the design of the facility, and failure to take these testing requirements into account during design does not constitute sufficient grounds for approval of an alternative test method.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of my staff at 404/347-5014.

Sincerely yours,

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

cc: Michael Harley, FL DEP

0004733

KBN

June 15, 1994

252916
PATS updated

1994 JUN 17 PM 2: 30
DER - MAIL ROOM
RECEIVED

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Request for Extension of Permit Expiration
Request for Permit Amendment
Orlando CoGen (I), Inc. Orlando CoGen Limited, L.P.
AC 48-206720; PSD-FL-184

Dear Clair:

This correspondence is submitted on behalf of Orlando CoGen Limited to request an extension of the permit expiration date. In addition, this correspondence modifies the permit amendment request in light of EPA's letter dated June 3, 1994.

Permit Expiration Request

The current construction permit expires on August 31, 1994. A 120-day extension is requested to accommodate a revised testing protocol made necessary by EPA's correspondence of June 3, 1994. In this correspondence, EPA indicates that the required approach to demonstrate compliance with the New Source Performance Standards (NSPS) Subpart Db emission limit (0.2 lb NO_x/MMBtu) is EPA Method 20 performed at both the combustion turbine (CT) outlet and the heat recovery steam generator (HRSG) stack. Subtracting the results of this simultaneous testing would provide information on compliance with the duct burners (DBs) with NSPS limits. In order to provide sufficient time to prepare the facility for testing in this manner, an extension is required. It is anticipated that the tests would be performed in August, 1994; thus, additional time is required to submit the tests and obtain an operating permit. A permit extension fee of $50.00 has been enclosed.

Permit Amendment

The EPA correspondence specifically addressed demonstrating compliance with the NSPS limits. As stated in our correspondence dated January 5, and February 22, 1994, the BACT limit is more stringent than the NSPS limit; thus the requested changes to the construction permit would not in any way affect the NSPS issues. Indeed, Specific Condition 16 separately addresses the requirement for the DBs to meet the NSPS. The requested changes are still appropriate for several reasons. First, there is no NSPS requirement to conduct annual testing to demonstrate compliance with the NSPS limit. Once testing is conducted to demonstrate compliance with the NSPS as indicated above, the facility would have met the obligation under these rules. Second, the proposed amendment (separate CT and CT/DB emission limits)

91134A1/17

would provide the Department with a clear approach of demonstrating compliance with the BACT limits. Simultaneous Method 20 testing is extremely costly and does not provide any more assurance of meeting the BACT limits. Moreover, the facility has a NO_x CEM that must be used to compare actual stack emissions with express CT and CT/DB limits; Specific Condition 13 of the current permit has this requirement. Thus, the requested changes to Table 1 only make the permit consistent with the Department's intent to regulate total emissions from the stack as provide for NO_x in Specific Condition 13.

Please note that the retesting of the facility using the simultaneous testing approach will cost about $75,000. This cost will not affect the emissions results since the alternate approach produced NO_x emission levels that were clearly in compliance with NSPS.

As always, your consideration in this matter is appreciated.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Tom Hess, Orlando CoGen (I), Inc.
Syed Arif, FDEP Tallahassee
Charles Collins, FDEP Orlando
Dennis Nester, Orange County EPD

3N ENGINEERING AND APPLIED SCIENCES, INC.
:INESVILLE, FL 32605

V-3922 012774

P... SE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	06/17/94	permit extension fee for Orlando CoGen (AC 48-206720; PSD-FL-184)		50.00

KBN Engineering and Applied Sciences, Inc.
GENERAL DISBURSEMENT ACCOUNT
PH. 904-331-9000
1034 N.W. 57TH STREET
GAINESVILLE, FL 32605

First Union National Bank of Florida
Gainesville, Florida 32605

63-2/630
Branch 311

012774
0004733

17 June 19 94

PAY ************50*** DOLLARS AND 00 CENTS $ ******50.00

TO THE ORDER OF
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee Fl 32399-2400

KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

⑈012774⑈ ⑆063000021⑆ 2131100925716⑈

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

June 9

Bureau of Air Regulation

DEPARTMENT OF ENVIRONMENTAL PROTECTION

JUN 08 1994

OFFICE OF THE SECRETARY

JUN 0 3 1994

4APT-AEB

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

SUBJECT: Construction Permit Amendment for Orlando CoGen Limited, L.P.

Dear Mr. Fancy:

This letter is in response to your March 1, 1994, request for clarification regarding the U.S. Environmental Protection Agency (EPA) position on a permit amendment and alternative NO_x compliance demonstration procedure proposed for a gas turbine and a duct burner in a combined cycle system operated by the referenced company. After reviewing the proposed permit amendment and alternative testing procedure, we have determined that we would be opposed to approval of either proposal.

Because of concerns about the difficulty associated with testing the duct burners in the combined cycle system at Orlando CoGen, KBN Engineering and Applied Sciences, Inc. (KBN) proposed revisions to NO_x emission limits and compliance testing procedures for the combined cycle system. The emission standard revision involved establishing two emission limits--a gas turbine emission limit and a combined limit for the gas turbine and duct burner operating together. Under this proposal, there would not be a separate limit for the duct burners, and the basis for this proposal was that the duct burners will never be operated alone.

After considering the KBN proposal for emission standard revisions, we have determined that it is not acceptable because one of the applicable regulations for the duct burners, 40 C.F.R. Part 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), contains a separate NO_x emission standard for duct burners in combined cycle systems. Since Subpart Db contains a NO_x emission limit specifically for duct burners, establishing a combined NO_x emission limit for the gas turbine and duct burner would not relieve Orlando CoGen of the obligation to demonstrate compliance with the applicable duct burner NO_x emission limit in Subpart Db.

The second proposal in the request from KBN involves compliance demonstration procedures for the duct burner. According to Subpart Db, the NO_x emission rate for duct burners is determined by measuring the emission rate at both the inlet and outlet of the duct burner. As an alternative to performing the test in accordance with Subpart Db, KBN proposed to determine the duct burner emission rate by performing all testing downstream of the duct burner and operating the combined cycle systems in two modes--one with only the turbine running and one with both the turbine and the duct burner operating. Under this scenario, the duct burner emission rate would be calculated by subtracting the turbine emission rate from the emission rate with both facilities operating. In support of this proposed alternative, KBN referenced a previous approval of similar procedures for combined cycle testing that was conducted at the Florida Power and Light (FP&L) Putnam Plant.

After considering the testing alternative proposed by KBN, we do not believe that it should be approved either. The basis for this position is that we are aware of other sources where similar procedures have yielded suspect results (i.e., NO_x mass emission rates with the gas turbine and duct burner operating together were lower than they were with only the turbine operating). The reason for these suspect results is uncertain, but they may have been caused by the inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.

Although procedures similar to those proposed by KBN were approved for the FP&L Putnam Plant, we do not consider this prior approval relevant with respect to Orlando CoGen because of differences in the two facilities. The primary justification for approving alternative testing procedures at the Putnam Plant was that these units were existing units that became subject to Subpart Db due to reconstruction. Although 40 C.F.R. §60.8(e) requires that a source owner or operator provide adequate testing and sampling locations, we did not necessarily consider these requirements applicable to FP&L since the Putnam units were not subject to Subpart Db at the time the units were originally constructed. Since the combined cycle system at Orlando CoGen is new, testing requirements should have been considered during the design of the facility, and failure to take these testing requirements into account during design does not constitute sufficient grounds for approval of an alternative test method.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of my staff at 404/347-5014.

Sincerely yours,

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

cc: Michael Harley, FL DEP
S. Arif

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Virginia B. Wetherell
Secretary

COMPLETENESS SUMMARY FOR AIR POLLUTION SOURCES

SOURCE NAME: **Orlando Cogen Limited, L.P.**

DATE RECEIVED: **April 11, 1994**

NAME: **Ronald D. Pettit, Operations Manager**

DATE REVIEWED: **May 9, 1994**

ADDRESS: **7201 Hamilton Boulevard Allentown, PA 18195-1501**

REVIEWED BY: **Louis Brown AC48-206720**

Your application for a modification to the operating permit for this referenced project has been received and reviewed for completeness. The following item(s) is/are needed from the professional engineer to complete your application.

1. **A Letter of Authorization designating Ronald D. Pettit, Operations Manager, as an Authorized Representative of Orlando Cogen Limited, L.P., must be submitted to this office.**

2. **This source is not in compliance with the NSPS, 40 CFR 60 Subpart Db, which requires the measurement of NO_X and oxygen at two sampling sites. One sampling site shall be located as close as is practical to the exhaust of the turbine, and the second site at the outlet to the steam generating unit. The source does not have sampling ports at the exhaust of the turbine. The request for modification of Construction Permit No. AC48-206720 must be approved and issued by the Department's Bureau of Air Regulation in Tallahassee before the operating permit for this facility can be processed.**

Pursuant to Section 120.60(2) F.S. , the Department may deny an application if the applicant, after receiving timely notice, fails to correct errors or omissions, or to supply additional information within a reasonable period of time.

If you have any questions, please call Louis Brown at (407)894-7555 or write to the above address.

Sincerely,

Charles M. Collins

Charles M. Collins
PE Administrator,
Air Resources Management

5-9-94
Date

lb
CMC/lbl

Copies furnished to:

Kennard F. Kosky
Clair Fancy ✓

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
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FROM: [illegible]
DATE 5/12
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DER 1893

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

March 1, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, NE
Atlanta, Georgia 30365

Dear Ms. Harper:

Re: Amendment of Construction Permit
Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC48-206720; PSD-FL-184

The Department needs some guidance from the EPA regarding an amendment request by KBN for the above referenced source. The documents enclosed with this letter are as follows:

1. KBN's amendment request dated January 5, 1994.
2. Department's incompleteness letter of January 27, 1994.
3. KBN's response to incompleteness letter dated February 22, 1994.

The issue of concern for the Department is the non-compliance by the source with the New Source Performance Standards (NSPS) requirements of 40 CFR 60, Subpart Db. The source is a 129-megawatt (MW) cogeneration facility consisting of a combustion turbine (CT) with a maximum heat input of 857 MMBtu/hr exhausting through a heat recovery steam generator (HRSG). The transition duct from the CT to the HRSG contains duct burners with a maximum heat input of 122 MMBtu/hr.

The applicable rule for the duct burners, 40 CFR 60.46 (f), Subpart Db, requires the measurement of NO_X and oxygen at two sampling sites. One sampling site shall be located as close as practicable to the exhaust of the turbine and the second site at the outlet to the steam generating unit. The source does not have sampling ports at the exhaust of the turbine.

Since the duct burner cannot be operated independently of the combustion turbine, the source is requesting the specification of individual limits for the CT and duct burners be changed to emission limits applicable to the CT operating alone and the CT and duct burners operating together. This change will not result in an increase in annual emissions. See the attached letter from Mr. Kosky, dated January 5, 1994.

Please indicate EPA's position on this issue of the source's non-compliance with NSPS requirements of testing as cited in Subpart Db. If there are any questions on the above, please call Syed Arif of my staff at (904) 488-1344.

The Department will not be able to take further action on the request for permit amendment until the response from EPA is received.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/SA/bjb

cc: Ken Kosky, KBN w/o attachments
Charles Collins, Central District w/o attachments
Dennis Nester, Orange County w/o attachments

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3. Article Addressed to:

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, NE
Atlanta, Georgia 30365

4a. Article Number

P 872 562 673

4b. Service Type

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☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery

3-07-94

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)

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Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 3/2/94 AC48-206720	

PS Form **3800**, JUNE 1991

KBN

February 22, 1994

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FEB 24 1994
Bureau of Air Regulation

Mr. John C. Brown, Jr., P.E.
Administrator, Air Permitting and Standards
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Amendment of Construction Permit
Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC48-206720; PSD-FL-184

Attention: Syed Arif

Dear Syed:

This correspondence presents additional information requested in the Department's letter dated January 27, 1994, concerning the request made to amend the above referenced permit. The information and comments are presented in the same order listed in the Department's January 27th letter.

Specific Condition 4

1. The change requested in Specific Condition 4 was made to differentiate the emission limits made for BACT and those applicable for NSPS. The reason this was requested was to distinguish between the applicable limits and provide a clear basis for future compliance. Thus, the issue of testing and location regarding NSPS would only apply to NOx and not the other pollutants. The Department can change this condition without affecting the NSPS or its associated testing issue.

There are no test ports that can meet the requirements to perform an EPA Method 20 in the transition duct between the CT and duct burners. This not only applies to this facility but to all that have been constructed in Florida (and presumably elsewhere to my knowledge). The reasons for this are:

a. high temperature (1,000°F) and positive pressure of flue gas.

b. an EPA Method 1 for locating flow rate measurements cannot be performed due to cyclonic flow and obstructions; it would not be possible to determine emissions rates in lbs/hr for NOx, CO and PM.

c. an EPA Method 20 could not be performed at this location due to the same problems with EPA Method 1.

91134A1/13

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street
Gainesville, Florida 32605
904-331-9000
FAX 904-332-4189

5405 West Cypress Street, Suite 215
Tampa, Florida 33607
813-287-1717 FAX 813-287-1716

1801 Clint Moore Road, Suite 105
Boca Raton, Florida 33487
407-994-9910
FAX 407-994-9393

6821 Southpoint Drive North, Suite 216
Jacksonville, Florida 32216
904-296-9663 FAX 904-296-0146

One Church Street, Suite 801
Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

Historically, all determinations of duct burner emissions were performed using the approach suggested in the testing protocol submitted to the Department for this cogeneration facility and discussed in the results. The test protocol was distributed to both the Central District and the Bureau's Emission Monitoring section and no adverse comments were received. The methodology used presented the "as close as practicable" location as the stack which can meet all EPA and DEP test location criteria. Tests were conducted with and without duct burner operation to determine emission rates. While the test was not conducted at the same time as suggested by the NSPS, the conditions were sufficiently representative to determine if the duct burners were in compliance with the NSPS, i.e., 0.2 lb/mmBtu. Having received no adverse comments on the test plan, testing was conducted, since as you are aware, it was important to perform test within the prescribed NSPS time frames.

I previously contacted EPA, including the author of the NSPS for Subpart Db [Rick Copeland (919)541-5265] and an individual from the EPA Emission Measurement Branch [Terry Harrison (919)541-5233] regarding this issue. Both are aware of the problem of determining compliance and have indicated that it is under review by EPA for change. Both indicated that the testing procedure involving "with and without duct burners" or a combined emission limit (i.e., turbine and duct burners) may be appropriate considerations given the technical problems of testing duct burners.

Again, the requested amendment to Specific Condition would not in any way affect the NSPS testing issue.

2. The cited section of the NSPS [40 CFR 60.46(e)(1)] applies only to sources that are required to have continuous emission monitoring system (CEMS) for NOx as required by Section 60.48b(b). Duct burner systems are exempt under 60.48b(h) from CEMS; please note that this section cites 60.44b(a)(4) which apply to duct burners used in combined cycle systems. The attached EPA letter confirms this observation.

<u>Specific Condition 7</u>

The purpose of requesting this change was for the ease of monitoring after the initial performance tests were conducted. It is recognized that EPA Method 20 is required for the initial compliance tests. However, the NSPS do not require annual compliance tests after the initial performance tests. Thus, the NSPS would not be contradicted if the Department specifies EPA Method 7e for annual compliance after the initial tests. Also, please note that the testing procedure used for determining compliance with the duct burners uses the appropriate methods; the only thing of issue is how the results are interpreted.

<u>Specific Condition 8</u>

There is difficulty using EPA Method 5 due to heated glass probe length and number of test locations. Since EPA Method 17 is equivalent to EPA Method 5 when the temperature is 250°F or greater, it is requested that EPA Method 17 be included in this Specific Condition. The data suggests that the EPA Method 17 criteria can be met at the cogeneration facility.

It is hoped that this information is sufficient to address your questions. However, it may be appropriate to meet with you on these issues to clarify any further questions. I would suggest the week of February 28th as an option. There is some time constraints, since these issues must be address before applying for the operating permit. I'll call in a few days. In the meantime, please call if you have any questions.

Sincerely,

Ken Kosky

Kennard F. Kosky, P.E.
President

cc: Tom Hess, Orlando CoGen (I), Inc.
Charles Collins, P.E., FDEP Central District
Dennis Nester, Orange County EPD

KFK/mlb

91134A1/13

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

January 27, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E.
KBN Engineering & Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

RE: Amendment of Construction Permit
Orlando CoGen (I), Inc.
AC48-206720; PSD-FL-184

Dear Mr. Kosky:

The Department has reviewed the request for changes to the above referenced construction permit. Listed below is the additional information required in order to continue processing this amendment request:

Specific Condition 4

1. Please indicate if there are sampling ports upstream of the duct burner (DB)? The applicable New Source Performance Standards (NSPS) for the DB's in 40 CFR 60.46(f), Subpart Db, require that the measurements of nitrogen oxides (NO_X) and oxygen shall be taken at two sampling sites. One sampling site shall be located as close as practicable to the exhaust of the turbine and the second site at the outlet to the steam generating unit. The NO_X emission rate from the combined cycle system is calculated by taking the difference of the measurements from the two sites. If this condition was not complied with, was a waiver obtained for their locations?

2. For the initial compliance test, 40 CFR 60.46(e)(1), Subpart Db, requires NO_X measurements from the steam generating unit to be continuously monitored for 30 successive steam generating unit operating days. The 30-day average emission rate is used to determine compliance with the NO_X emission standards. Please provide a copy of these test data.

The two requirements above are included in Specific Condition 16 of the air construction permit.

Specific Condition 7

Since the applicable NSPS (Subparts Db and GG) require that EPA Method 20 be used for determining NO_X emissions, the change for this specific condition will require submittal of an alternate sampling procedures request as outlined in 17-297.620.

Specific Condition 8

1. Please explain the reasons for using EPA Method 17 in lieu of EPA Method 5? EPA Method 17 has a stack temperature limitation. Can this condition be met?

We will resume processing the amendment after the requested information is received. Should you have any questions on this matter, please contact Syed Arif at (904) 488-1344.

Sincerely,

John C. Brown, Jr.

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JB/SA/bjb

cc: Charles Collins, Central District
Dennis Nester, Orange County

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KBN Engineering & Applied Sciences
1034 N.W. 57th Street
Gainesville, Florida 32605

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P 872 562 586

4b. Service Type
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P 872 562 586

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KBN

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January 5, 1994

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC48-206720; PSD-FL-184; Orange County
Request for Modification of Construction Permit

Dear Clair:

This correspondence is submitted on behalf of Orlando CoGen (I), Inc., to request some minor changes to the construction permit issued for the facility. The source is a 129-megawatt (MW) cogeneration facility located in Orlando Central Park, Orange County, Florida. The cogeneration facility consists of a combustion turbine (CT) exhausting through a heat recovery steam generator (HRSG). The transition duct from the CT to the HRSG contains duct burners (DBs) with a maximum heat input of 122 million British thermal units per hour (MMBtu/hr).

The construction permit was issued August 17, 1992, and expires August 31, 1994. Initial compliance tests were performed on October 12-15, 1993, and revealed some areas where changes to permit conditions are requested. Changes to Specific Conditions 4, 7, and 8 are requested.

Please be advised, however, that this request does not constitute any change in total emissions from the facility. Moreover, the initial tests for the facility demonstrated that the combustion turbine can achieve and nitrogen oxide (NO_x) emission concentration of **15 parts per million (volume) dry** (ppmvd) corrected to 15 percent oxygen (O_2). This extremely low emission rate is currently the **lowest demonstrated** among all cogeneration facilities in the State of Florida.

Specific Condition 4
This condition sets forth the emission limits for the facility (see attached Specific Conditions 4, 7, and 8). The allowable emission standards/limitations are expressed in terms of individual limits for the CT and the DBs. For NO_x, the allowable emission standards are based on 15 ppmvd at 15 percent O_2 for the CT and 0.1 lb/MMBtu heat input for the DBs. The applicable new source performance standards (NSPS) for the CT is Subpart GG which specifies an emission concentration of 75 ppmvd at 15 O_2 and corrected for heat rate (this equates to 94 ppmvd at 15 percent O_2). For the DBs, the applicable NSPS is Subpart Db which specifies an maximum emission rate of 0.2 lb/MMBtu. Emission-limiting standards are also limited for carbon monoxide (CO), particulate matter (PM)/PM10, volatile organic compounds (VOCs), and visible emissions (VE). There are no applicable NSPS for these pollutants. Only natural gas is used as fuel at the facility.

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189
5660 West Cypress Street, Suite I, Tampa, Florida 33607, 813-287-1717, FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910, FAX 407-994-9393
6821 Southpoint Drive North, Suite 216, Jacksonville, Florida 32216, 904-296-9663, FAX 904-296-0146
One Church Street, Suite 801, Rockville, Maryland 20850, 301-738-1100, FAX 301-738-1105

It is requested that the Department consider changing the specification of individual limits for the CT and DBs to emission limits applicable to the CT operating alone and the CT/DBs operating together. Attached is the requested terminology for Specific Condition 4. As noted, there will be **no increase in annual emissions** with this requested change to the permit. The reasons for this request are threefold. First, the large volume flow rate of the CT could produce erroneous results when compliance with DB emissions is determined (see attached test report). The combination of large flow rate and smaller emission contribution from the DBs can produce substantial apparent errors when none exist.

Second, determining the emission status of the facility will be much easier for the Department by having specific limits for the CT and CT\DB combination. Since the facility has installed a continuous emission monitoring (CEM) system for NO_x, determining the emission status would be directly evident.

Third, the DBs cannot be operated without the CT; therefore, it is logical to specify emission limits for the combination rather than separately.

It is recognized that the DBs must independently demonstrate compliance with NSPS. It is proposed that this be accomplished separately through requested changes to Specific Condition 7 (see discussion below). The specific reference to NSPS is contained in Specific Condition 16. Please note that the basis of the requested CT/DB emission limit does not change the original basis of 0.1 lb/MMBtu. Indeed, a combined limit must be met during annual compliance tests when both CT and the DBs are at 90 to 100 percent of full load. Therefore, the emissions cannot exceed the original emission basis of 15 ppmvd at 15 percent O_2 for the CT and 0.1 lb/MMBtu for the DBs.

Specific Condition 7
It is requested that this condition be changed to allow the use of EPA Method 7e for determining future compliance with Specific Condition 4. Determining initial compliance with NSPS for the CT has been conducted using EPA Method 20. The results clearly demonstrate that NSPS is achieved by this very low-NO_x emitting machine. Compliance with NSPS for the DBs was determined using EPA Method 20 and demonstrating compliance with the NO_x emission limit of 0.2 lb/MMBtu.

Please note that this approach is consistent with that approved by the Department for the Florida Power & Light Company Putnam Plant. In this case, the Department allowed testing of four HRSGs with DBs using the proposed approach. The DBs for this facility have a higher firing rate that the Orlando CoGen facility and Subpart Db applied.

Specific Condition 8
It is requested that this condition allow the use of EPA Method 17.

PERMIT FEE

A permit fee of $250 as specified by Rule 17-4.050(4)(p)5. F.A.C. is attached to this request.

Please call if you have any questions. If it is necessary to meet on this request, I and representatives of Orlando CoGen would be available at your and your staff's convenience. As always, your consideration in this matter is appreciated.

Sincerely,

Kennard F. Kosky, P.E.
President
Florida Registration No. 14996

SEAL

KFK/mk

cc: Tom Hess, Orlando CoGen (I), Inc.
Bruce Mitchell, FDEP BAR
Charles Collins, P.E., FDEP Central District
Dennis Nester, Orange County EPD
File (2)
C. Holladay
G. Harper, EPA
J. Bunyak, NPS

CURRENT CONDITIONS IN AC 48-206720

Specific Conditions

4. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NO_x	CT	15 ppmvd @ 15% O_2 (57.4 lbs/hr; 251.4 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
	CT/DB	24-hr rolling average
CO	CT	10 ppmvd (22.3 lb/hr; 92.1 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
PM/PM_{10}	CT	0.01 lb/MMBtu (9.0 lbs/hr; 39.4 TPY)
	DB	0.01 lb/MMBtu (1.2 lbs/hr; 2.2 TPY)
VOC	CT	3.0 lbs/hr; 13.0 TPY
	DB	3.7 lbs/hr; 6.8 TPY
VE	CT/DB	≤ 10% opacity

NOTE:
1. CT: combustion turbine
   DB: duct burner
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr (at a maximum heat input of 122.0 x 10^6 Btu/hr)
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. DB operation planned when ambient temperature is greater than 59°F.

7. Initial and subsequent annual compliance tests shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1991 version of the 40 CFR 60, Appendix A.
a. EPA Method 5 for PM
b. EPA Method 10 for CO
c. EPA Method 9 for VE
d. EPA Method 20 for NO_x

Note: Other test methods may be used for compliance testing only after prior Department written approval.

8. EPA Method 5 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

REQUESTED CHANGES IN AC 48-206720

Specific Conditions

4. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NO_x	CT	15 ppmvd @ 15% O_2; 57.4 lbs/hr; 251.4 TPY
	CT/DB	69.6 lbs/hr; 273.9 TPY
	CT/DB	24-hr rolling average
CO	CT	10 ppmvd; 22.3 lbs/hr; 92.1 TPY
	CT/DB	34.5 lbs/hr; 114.6 TPY
PM/PM_{10}	CT	0.01 lb/MMBtu; 9.0 lbs/hr; 39.4 TPY
	CT/DB	10.2 lbs/hr; 41.6 TPY
VOC	CT	3.0 lbs/hr; 13.0 TPY
	CT/DB	6.7 lbs/hr; 19.8 TPY
VE	CT or CT/DB	$\leq$ 10% opacity

NOTE:
1. CT: combustion turbine alone
   CT/DB: CT with duct burner (DB) in operation
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr (at a maximum heat input of 122.0 x 10^6 Btu/hr)
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. DB operation planned when ambient temperature is greater than 59°F.

7. Initial and subsequent annual compliance tests shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1993 version of the 40 CFR 60, Appendix A.
a. EPA Method 5 or 17 for PM
b. EPA Method 10 for CO
c. EPA Method 9 for VE
d. EPA Method 20 for NO_x (initial) and EPA Method 7e (annually)

Note: Other test methods may be used for compliance testing only after prior Department written approval.

8. EPA Method 5 or 17 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

Emissions Performance Test Results

and CEMS Performance Specification Test Results

for

Orlando CoGen Limited

(October 12-15, 1993)

Part A (Results)

Prepared by:

Tom Hess
Air Products and Chemicals, Inc.
1 December 1993

Part A

Contents

Tables

Part B

Contents

Introduction

Emission tests were conducted at Orlando CoGen Limited, "OCL", on a combined-cycle natural gas-fired power plant over the period of 12 October - 15 October. These tests were performed to show compliance with:

- Florida Department of Environmental Regulation Permit No.: AC 48-206720/PSD-FL-184 issued 17 August 1992

- EPA NSPS Subpart GG (combustion turbines)
  EPA NSPS Subpart Db (duct burners)

- EPA Performance Specifications 2 and 6 (NOx continuous emission monitoring system).

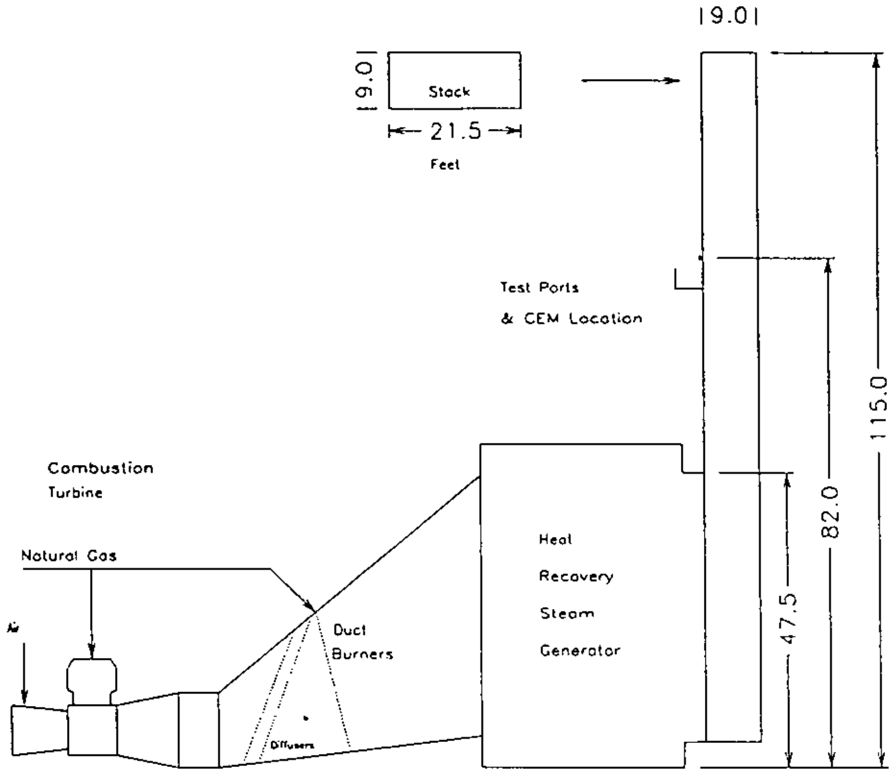
As summarized in Table 1 (page 5), the combined cycle plant meets its total emissions limits for PM, CO, NOx, and visual emissions in its two operating modes: 1)combustion turbine only firing; and 2) combustion turbine firing with auxiliary firing in the duct burners of the heat recovery steam generator.

This report is divided into two parts. Part A, this part, describes the facility, the test program, and gives a summary of all test results compared to emission limitations. Also included are the results of the performance specification tests for the NOx continuous emission monitoring system. Part B contains all raw test data and QA/QC procedures.

Tests were observed by Mr. Dennis Nester of the Orange County Environmental Protection Department and were carried out by Air Consulting and Engineering of Gainesville, Florida.

Facility Description

The OCL facility generates electricity and a small amount of process steam from a single natural gas-fired combustion turbine, "CT", followed by a heat recovery steam generator. Combustion of natural gas occurs primarily in the combustion turbine, but when additional thermal energy is needed, an additional small amount of natural gas is fired in the steam generator portion of the plant in duct burners, "DB". However, no additional combustion air is required for duct burner firing since the turbine exhaust gases have sufficient oxygen to support combustion of gas at the duct burners.



The combustion turbine drives a single generator which is also coupled to low and high pressure steam turbines driven by steam produced in the heat recovery steam generator. During warm weather, when the combustion turbine is limited in its capacity, supplementary firing in the duct burners in the steam generator provides additional steam allowing the plant to maintain its generating capacity.

The duct burners *can not be independently fired,* since the burners rely on the turbine exhaust to provide oxygen for combustion. Therefore, there are only two plant operating modes: 1) combustion turbine (CT) only firing; and 2) combustion turbine plus duct burner firing (CT +DB). Emission tests were conducted to determine emissions for both of these operating modes.

Summary of Results

DER Permit

The following table gives the results of emission tests demonstrating compliance with the DER permit emission limitations. For the maximum firing case (CT +DB) the turbine and duct burners were fired at 95% of the maximum permitted values. All emissions requirements were met. Test data for the case of combustion turbine only (CT) firing, again at 95% of the allowable operating rate, also indicate emissions less than permit values. Complete details of each test run can be found in the section Detailed Summary of Results (page 10).

HHV vs LHV

Table 1. Summary of Emission Test Results

	CT+DB		CT Only		DB Only *	
	Measured	Emission Standard	Measured	Emission Standard	Measured	Emission Standard
	10/12/93 2,3,4-avg		10/13/93 1,2,3-avg		10/12/93 2,3,4-avg	
Gross Power, MW	123.0		115.2		123.0	
MMBtu/hr LHV** CT	778.2		787.3			
MMBtu/hr LHV CT, ISO	812.8	<856.9	811.2	856.9		
Percent of Allowable	94.9		94.7			
MMBtu/hr LHV, DB	116.4	<122.0			116.4	<122.0
Percent of Allowable	95.4				95.4	
NOx, lbs/MMBtu (LHV)	0.06013	n/a	0.05328	n/a	0.1	0.1
NOx, ppmvd ISO 15%O2d	n/a	n/a	13.80	15	n/a	n/a
NOx, lbs/hr	64.8	69.6	49.8	57.4	14.3	12.2
CO, ppmvd	0.0790	n/a	0.014	10	n/a	n/a
CO, lbs/MMBtu (LHV)	0.00019	n/a	0.00004	n/a	0.0012	0.1
CO, lbs/hr	0.20	34.5	0.04	22.3	0.16	12.2
PM, lbs/MMBtu (LHV)	0.00851	n/a	0.00673	0.01	0.02	0.01
PM, lbs/hr	8.96	10.2	6.30	9.0	2.7	1.2
Visible emissions	0	10	0	10	n/a	n/a

HHV

Is this an emission limit?

* Determined as the difference in emissions with and without duct burners using EPA Method 19 as explained below.

** Lower Heating Value

Also reported are the emissions that may be attributable to the duct burners. However, it must be noted that there is no way to directly determine emissions from duct burners since they cannot be operated independently of the combustion turbine. As a result, estimated emissions of the duct burners must be determined by the difference in emissions between the case of turbine operation with duct burner firing (CT+DB), and the case of combustion turbine operation alone (CT).

From Method 19 of 40 CFR 60, the following equation (19-10) is used to estimate emissions from the duct burners using test results:

$$E_{DB} = E_{(CT+DB)} + \frac{H_{CT}}{H_{DB}} \cdot (E_{(CT+DB)} - E_{CT})$$

where E is lbs of emission/MMBtu and H is the heat input in MMBtu/hr. Care must be taken to consistently use the correct convention for the heat input basis. For all calculations reported here, the lower heating values are used since this is the basis of the permit.

As is evident from the equation, large errors may result in the estimate for E_{DB} from small measurement errors in $E_{(CT+DB)}$ and E_{CT}. It's the classic case of the large error associated with taking the difference in two very small numbers. At the low levels of NOx and PM emitted by this plant, relative errors in measurements are likely to be quite high. Further, any errors in measurement are magnified by the ratio of H_{CT} to H_{DB}. Therefore, because duct firing is a small fraction of total gas firing, large errors in the calculation of NO_x and PM emissions attributable to DB firing will result from small errors in measurement in those variables.

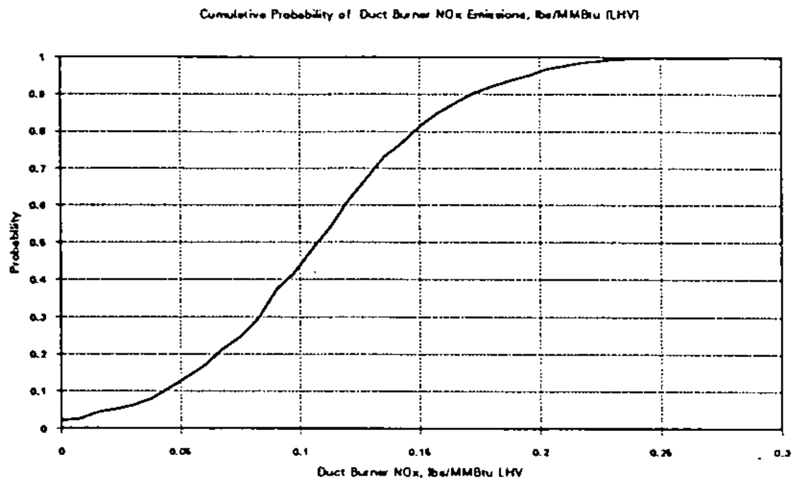
For example, substituting the test results for NO_x from the table above yields

$$E_{DB} = 0.06013 + \frac{778.2}{116.4} \cdot (0.06013 - 0.05328) = 0.1059$$

However, with only a 3% measurement error in $E_{(CT+DB)}$ <u>or</u> E_{CT}, the estimate for E_{DB} becomes (assuming the entire error is in $E_{(CT+DB)}$)

$$E_{DB} = 0.05833 + \frac{778.2}{116.4} \cdot (0.05833 - 0.05328) = 0.09209$$

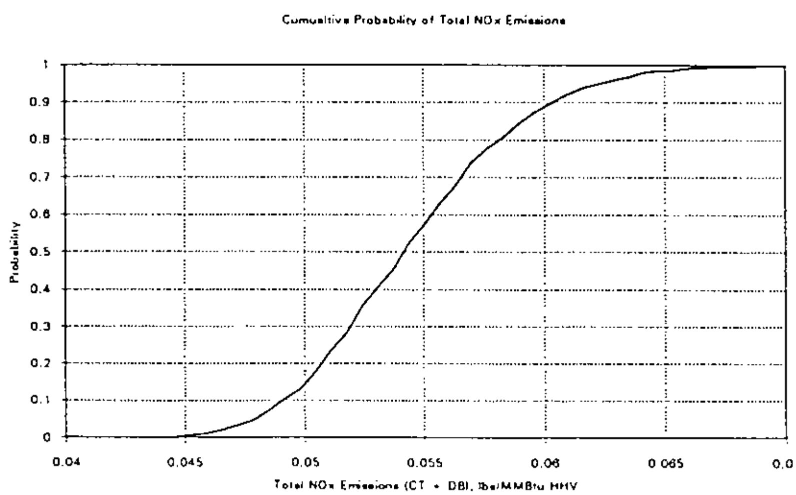
This is over a 13% error in the estimate for E_{DB}. In fact, this calculation understates the uncertainty in the estimate of the duct burner NOx emissions. Four measurements are required to determine E_{DB}: NOx, for DB+CT firing; O_2, for DB+CT firing; NOx, for CT only firing; and O_2 for CT only firing. There is some measurement error associated with all four values, all of which contribute to the error in determining NOx emissions due to the duct burners. To illustrate this more fully, a Monte-Carlo simulation was performed to generate the cumulative probability distribution of E_{DB}. In the simulation it is assumed that measurement error is normally distributed with standard deviation of 3% of the mean of the measurements. For example, the observed value of NOx for the CT was 11.8 ppm, so that the standard deviation for this measurement was assigned a value of 0.35 ppm. Results are shown graphically in the following figure.



The graph shows the effect of these measurement errors in the resulting distribution of calculated values for duct burner NOx, E_{DB}. As shown, the uncertainty in E_{DB} for NOx is very high- the 90th percentile being 65% higher than the mean. For the estimated mean value of 0.106 there is a 40% chance that the true value is actually less than about 0.090 lbs/MMBtu. Another way of thinking about this graph, is that the true emissions performance of the duct burners would have to be less than about 0.04 lbs/MMBtu to have a 90% chance of passing an emission test given the uncertainty in the individual NOx and O_2 measurements.

The accuracy of measurement of particulate matter at these low emission rates is even more of a problem since accurate PM measurements at low emission rates is more difficult than measuring gas concentrations.

However, it should be kept in mind that firing duct burners independently of the combustion turbine is meaningless as well as physically impossible. Again, the combined cycle plant meets the permit's emission limitations under its only two operating modes: combustion turbine operation alone, and combustion turbine operation with gas firing in the duct burners. For total emissions, the uncertainty is much smaller, since the difference in two small numbers does not enter into the calculation of total emissions. As shown below for the simulation of total emissions, the 90th percentile value is only 11% higher than the mean.



New Source Performance Standards

Subpart GG-Stationary Gas Turbines

The following table gives the NSPS emission standards applicable to the combustion turbine compared to observed emissions performance. In all cases observed emissions reported are the average from three runs conducted at a given firing rate. The combustion turbine firing rates were selected to represent the normally expected operating range of the plant.

Table 2. NSPS Subpart GG Performance (Combustion Turbine)

Pollutant	Turbine Firing Rate, Percent of Allowable at ISO conditions (856.9 MMBtu/hr, LHV)	Standard	Observed Emission
NOx	94.7	94 ppmvd, 15% O_2, at a rated heat rate of 11.5 KJ/Watt-hr	13.8 ppmvd, 15% O_2, ISO
	81.9	"	13.5, "
	87.0	"	11.4, "
	92.6	"	12.8, "
SO_2	Average of four fuel samples	Fuel sulfur < 0.8% by weight	0.0035 weight % S

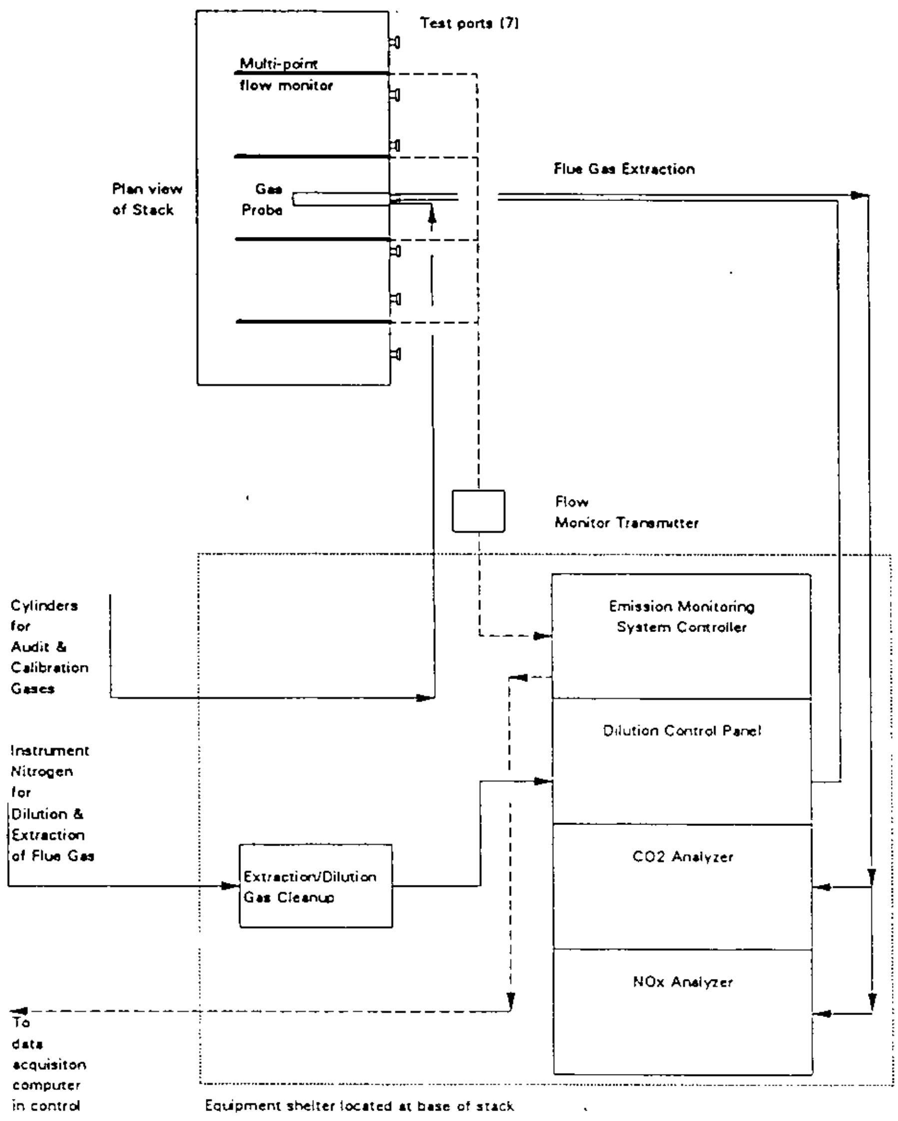
Subpart Db-Duct Burners

The only new source performance standard applicable to natural gas fired duct burners is a limit of 0.2 lbs NOx/MMBtu heat input to the duct burners. The observed NOx emission rate was only 0.1 lbs NOx/MMbtu (see Table 1).

Continuous Emission Monitoring System-Performance Specification Tests

Emission Monitoring System

This plant is equipped with a continuous emission monitoring system to monitor the emission rate of NOx in units of lbs/hr. As shown in the following diagram, the continuous emission monitoring system (CEMS) measures the concentrations of NOx, CO_2, and the flow rate of flue gas leaving the stack following the HRSG. Flue gas is extracted from the stack using purified nitrogen to carry it to CO_2 and NOx analyzers housed in an air conditioned shelter at the base of the stack. The dry nitrogen carrier gas, by diluting the sample, lowers its dew point enough that no moisture removal is necessary prior to passing the gas sample to the analyzers. Because no moisture is removed in the sampling process, all concentrations are therefore on a wet basis.



Flue gas flow rate is monitored at multiple points in the plane of the stack using differential pressure. The multi-point readings are integrated and compensated for temperature and pressure to produce a flow rate in standard cubic feet per minute.

Other components of the system are:

- A system controller which takes instrument readings and converts the analyzer outputs into the correct signal for transmission to the data acquisition computer. The controller also controls the injection of reference gases for system calibration and auditing.

- The dilution control panel controls the flow of extraction gas to the gas sample probe in the stack.

- The extraction gas cleanup module removes moisture, NOx, and CO_2 which may be present in the nitrogen carrier used to extract flue gas from the stack.

Data Acquisition

Data from the analyzers is transmitted via the system controller to a dedicated microcomputer which logs the measurement data (ppm NOx, %CO_2, and SCFM flow) and performs calculations to convert the measurements to other units, such as lbs/hr, and lbs/MMBtu. Additional functions include:

- tracking cumulative emissions,
- recording results of daily and quarterly cylinder gas checks and audits of the CEMS,
- producing alarms if permitted emissions are exceeded or monitor malfunctions are detected,
- recording status of the monitoring system,
- and producing emission reports required by permits and regulations.

Performance Requirements

Performance specifications currently applicable to the monitoring system are contained in 40 CFR 60 App. B Spec. 2 (NOx monitor) and Spec. 6 (NOx rate monitoring). The following table summarizes the results of the performance specification tests for relative accuracy and the 7-day zero and calibration drift tests. Complete results are given in the Detailed Performance Specification Test Results section (page 16).

Table 3. CEMS Performance Specification Test Results

Specification	Standard	Observed Result
Relative accuracy of NOx analyzer	< 20% error at 95% confidence	3.42% in units of ppmw NOx
Relative accuracy of NOx continuous emission rate monitor	< 20% error at 95% confidence	1.63% in units of lbs/hr NOx
Zero Drift NOx analyzer	< 2.5% of span	Max. 0.08%
Span Drift NOx analyzer	< 2.5% of span	Max. 0.80%

Detailed Summary of Results

The following table summarizes the test conditions for each run performed during the emission performance and CEMS performance specification tests. Tables 5, 6, and 7 following give results for each test as well as relevant plant performance data. Part B of the report contains the field data used in preparing the test results given in Tables 5, 6, and 7. Table 4 also indicates in which section of Part B the relevant test data can be found for each test run. Part B also contains all strip charts, field data, laboratory reports, QA/QC data for the emission tests, and NOx CEM RATA/drift data.

The following test methods were used to determine emissions:

EPA Method 20	NOx
EPA Method 10	CO
EPA Method 5	PM
EPA Method 9	Visible Emissions

Table 4. OCL Emission Test Log

Run	Date, Time	Plant Operating Condition	Tests	*Part B Tab*	Remarks
1	10/12, 07:47-10:10	Maximum CT firing, but variable duct burner firing		1	Data for this run is reported in Part B, but operations were not steady and did not represent maximum gas firing. Results not used in evaluation of performance.
2	10/12, 11:23-13:33	Maximum CT & DB firing	PM, NOx, CO, VE x 2, flow, CO_2, O_2		
3	10/12, 14:13-16:18	"	" (VE x 2)		
4	10/12, 16:48-18:53	"	" (no VE)		
1	10/13, 07:48-09:51	Maximum CT firing, no DB firing	PM, NOx, CO, CO_2, O_2, flow	2	Duct burner emissions are determined by difference between PM, NOx, and CO emissions with DB (runs 2-4) and without DB firing (runs 5-7). Slight variations in firing rates are taken into account by weighting emissions on heat input basis using EPA Method 19 (equation 10).
2	10/13, 10:55-13:43	"	"		
3	10/13, 14:31-16:42	"	"		
1	10/14, 08:12-10:04	Nominal 80% firing rate of CT. No DB firing	NOx, CO_2, O_2, flow	3	
2	10/14, 11:04-12:03	"	"		CEMS relative accuracy performance specification test (RATA 1).
3	10/14, 12:23-13:20	"	"		RATA 2
1	10/14, 14:08-15:06	Nominal 87% firing rate of CT. No DB firing	NOx, CO_2, O_2, flow	4	RATA 3
2	10/14, 15:40-16:29				RATA 4
3	10/14, 16:36-17:25				RATA 5
1	10/15, 07:44-08:35	Nominal 94% firing rate of CT. No DB firing	NOx, CO_2, O_2, flow	5	RATA 6
2	10/15, 09:07-9:56				RATA 7
3	10/15, 10:16-11:11				RATA 8
1A	10/15, 11:28-12:27	Nominal 100% CT firing. No DB firing.	NOx, CO_2, O_2, flow	6	RATA 9
2A	10/15, 13:30-14:30	Nominal 100% CT firing. Reduced rate DB firing	NOx, CO_2, O_2, flow	7	RATA 10
3A	10/15, 16:48-17:22	Nominal 100% CT firing. High DB firing.	NOx, CO_2, O_2, flow	8	RATA 11

Table 5. Emission Test Results/Plant Operating Data for 10/12 &13 (Base Cases w & w/o Duct Burners)

OCL Emission Tests	12-Oct	12-Oct	12-Oct		13-Oct	13-Oct	13-Oct	
	CT+DB	CT+DB	CT+DB		CT	CT	CT	
	Run 2	Run3	Run 4	Average	Run 1	Run 2	Run 3	Average
Start Test Run	11:23	14:13	16:48		7:48	10:55	14:31	
Stop Test Run	13:33	16:18	18:53		9:51	13:43	16:42	
MW Generator	123.6	122.6	122.7	123.0	118.0	114.6	113.1	115.2
GT KSCFH nat. gas	852.2	842.3	843.0	845.9	886.0	842.6	841.6	856.7
DB KSCFH nat. gas	126.2	125.2	126.5	126.0	0.0	0.0	0.0	0.0
GT MMBtu/hr HHV	870.1	860.0	860.7	863.6	903.7	859.5	858.4	873.9
GT MMBtu/hr LHV	784.1	775.0	775.6	778.2	814.2	774.4	773.4	787.3
DB MMBtu/hr HHV	128.9	127.9	129.2	128.6	0.0	0.0	0.0	0.0
DB MMBtu/hr LHV	116.1	115.2	116.4	115.9	0.0	0.0	0.0	0.0
Turbine ISO Heat Input LHV	815.1	811.0	812.3	812.8	825.7	800.9	807.1	811.2
Mean Barometric Pressure, inHg	29.95	29.95	29.95		30.02	30.02	30.02	
Mean RH%	55.9	43.3	43.0		86.4	54.9	43.9	
Mean Temp, °F	76.5	81.1	81.5		64.1	75.4	80.8	
Abs. humid (lb water/lb dry air)	0.0108	0.0097	0.0098		0.0110	0.0102	0.0098	
F factor, SCF/MMBtu HHV	8482	8482	8482		8481	8481	8481	
HHV Btu/SCF nat. gas	1021	1021	1021		1020	1020	1020	
LHV Btu/SCF nat. gas	920	920	920		919	919	919	
Stack temperature, °F	242.6	244.4	244.3		252.2	248.1	251.1	
Stack pressure, inHg	29.89	29.89	29.89		29.96	29.95	29.95	
Stack moisture, %	7.68	8.53	7.67		7.11	7.214	7.165	
O_2, %dry	14.90	14.80	14.90		15.80	15.70	15.60	
CO_2, %dry	3.40	3.40	3.40		2.90	3.00	3.00	
Stack actual flow rate, ACFM	834423	807776	851864		862307	856175	843116	
Stack standard flow rate, SCFMD	578347	553309	589058		594584	592966	581780	
Particulate total catch, mg	10.8	11.5	10.1		6.5	5.6	11.2	
Volume sampled, SCFD	94.49	86.56	93.50		101.8	97.05	92.268	
Particulate, lbs/MMBtu, HHV	0.00745	0.00851	0.00704	0.00766	0.00489	0.00434	0.00895	0.00606
Particulate, lbs/MMBtu, LHV	0.00826	0.00945	0.00781	0.00851	0.00543	0.00481	0.00993	0.00673
Particulate, lbs/hr	8.74	9.72	8.42	8.96	5.02	4.53	9.34	6.30
NOx, ppmvd	15.51	15.50	15.36	15.46	11.07	12.06	12.27	11.80
NOx, ppmvd 15%O_2, ISO	n/a	n/a	n/a		13.79	13.92	13.69	13.80
NOx, lbs/MMBtu HHV	0.05471	0.05378	0.05418	0.05422	0.04593	0.04908	0.04899	0.04800
NOx, lbs/MMBtu LHV	0.06072	0.05968	0.06013	0.06018	0.05098	0.05447	0.05438	0.05328
NOx, lbs/hr	64.26	61.43	64.81	63.5	47.15	51.23	51.13	49.8
CO, ppmvd	0.088	0.078	0.071	0.0790	0.043	0	0	0.014
CO, lbs/MMBtu HHV	0.00019	0.00016	0.00015	0.00017	0.00011	0.00000	0.00000	0.00004
CO, lbs/MMBtu LHV	0.00021	0.00018	0.00017	0.00019	0.00012	0.00000	0.00000	0.00004
CO, lbs/hr	0.22	0.19	0.18	0.20	0.11	0.00	0.00	0.04
Visual Emissions, % opacity	0	0	0	0	0	0	0	
Period of Observation	11:25	11:55	14:15	14:45	7:50	10:54	14:35	
	11:55	12:25	14:45	15:15	8:50	11:54	15:35	

Table 6. Emission Test Results/Plant Operating Data for 10/14 (CT Turndown Cases)

OCL Emission Tests	14-Oct	14-Oct	14-Oct		14-Oct	14-Oct	14-Oct	
	CT 80%	CT 80%	CT 80%		CT 87%	CT 87%	CT 87%	
	Run 1	Run 2	Run 3	Average	Run 1	Run 2	Run 3	Average
		RATA 1	RATA 2		RATA 3	RATA 4	RATA 5	
Start Test Run	8:12	11:04	12:23		14:08	15:40	16:36	
Stop Test Run	10:04	12:03	13:20		15:06	16:29	17:25	
MW Generator	96.13	94.59	94.24	95.0	101.40	100.81	100.55	100.9
GT KSCFH nat. gas	736.80	729.35	728.90	731.7	771.83	767.22	768.85	769.3
DB KSCFH nat. gas	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
GT MMBtu/hr HHV	750.1	742.5	742.0	744.9	785.7	781.0	782.7	783.1
GT MMBtu/hr LHV	676.4	669.5	669.1	671.7	708.5	704.3	705.8	706.2
DB MMBtu/hr HHV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB MMBtu/hr LHV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Turbine ISO Heat Input LHV	700.2	701.6	704.0	701.9	744.4	741.4	750.3	745.4
Mean Barometric Pressure, inHg	30.02	30.13	30.02		30.07	30.07	30.07	
Mean RH%	85.8	78.9	72.1		67.71	60.1	69.6	
Mean Temp, °F	72.2	79.0	80.0		80.71	82.6	84.9	
Abs. humid (lb water/lb dry air)	0.0145	0.0167	0.0158		0.0151	0.0143	0.0179	
F factor, SCF/MMBtu HHV	8480	8480	8480		8480	8480	8480	
HHV Btu/SCF nat. gas	1018	1018	1018		1018	1018	1018	
LHV Btu/SCF nat. gas	918	918	918		918	918	918	
Stack temperature, °F	250	248	247		241	244	243	
Stack pressure, inHg	29.93	29.93	29.93		30.03	30.03	30.03	
Stack moisture, %	8.6	8.6	8.6		7.5	7.5	7.5	
O_2, %dry	15.60	15.70	15.70		15.40	15.30	15.38	
CO_2, %dry	3.00	3.00	3.00		3.20	3.18	3.12	
Stack actual flow rate, ACFM	735697	719720	714460		704532	703977	697879	
Stack standard flow rate, SCFMD	500464	491121	488137		492405	490462	486523	
Particulate total catch, mg	N/A	N/A	N/A		N/A	N/A	N/A	
Volume sampled, SCFD	N/A	N/A	N/A		N/A	N/A	N/A	
Particulate, lbs/MMBtu, HHV	N/A	N/A	N/A		N/A	N/A	N/A	
Particulate, lbs/MMBtu, LHV	N/A	N/A	N/A		N/A	N/A	N/A	
Particulate, lbs/hr	N/A	N/A	N/A		N/A	N/A	N/A	
NOx, ppmvd	9.99	10.01	9.82	9.94	9.69	9.63	9.24	9.52
NOx, ppmvd 15%O_2, ISO	12.54	13.54	14.54	13.54	11.46	11.10	11.50	11.35
NOx, lbs/MMBtu HHV	0.03988	0.04073	0.03996	0.04019	0.03728	0.03639	0.03542	0.03636
NOx, lbs/MMBtu LHV	0.04423	0.04517	0.04431	0.04457	0.04134	0.04035	0.03928	0.04032
NOx, lbs/hr	35.81	35.22	34.34	35.1	34.18	33.83	32.20	33.4
CO, ppmvd	1.41	1.55	1.46	1.4733	0.00	0.00	0.00	0.0000
CO, lbs/MMBtu HHV	0.00343	0.00384	0.00362	0.00363	0.00000	0.00000	0.00000	0.00000
CO, lbs/MMBtu LHV	0.00380	0.00426	0.00401	0.00402	0.00000	0.00000	0.00000	0.00000
CO, lbs/hr	3.08	3.32	3.11	3.17	0.00	0.00	0.00	0.00

Table 7. Emission Test Results/Plant Operating Data for 10/15 (CT Turndown Case)

OCL Emission Tests	15-Oct	15-Oct	15-Oct		15-Oct	15-Oct	15-Oct
	CT 94%	CT 94%	CT 94%		CT	CT+DB	CT+DB
	Run 1	Run 2	Run 3	Average	Run 1A	Run 2A	Run 3A
	RATA 6	RATA 7	RATA 8		RATA 9	RATA 10	RATA 11
Start Test Run	7:44	9:07	10:16		11:28	13:30	16:48
Stop Test Run	8:35	9:56	11:11		12:27	14:30	17:22
MW Generator	109.83	108.99	107.93	108.9	112.43	118.53	123.20
GT KSCFH nat. gas	827.19	825.96	816.70	823.3	849.33	840.67	854.0
DB KSCFH nat. gas	0.00	0.00	0.00	0.0	0.00	103.33	123.73
GT MMBtu/hr HHV	844.6	843.3	833.9	840.6	867.2	858.3	871.9
GT MMBtu/hr LHV	761.0	759.9	751.4	757.4	781.4	773.4	785.7
DB MMBtu/hr HHV	0.0	0.0	0.0	0.0	0.0	105.5	126.3
DB MMBtu/hr LHV	0.0	0.0	0.0	0.0	0.0	95.1	113.8
Turbine ISO Heat Input LHV	792.3	795.1	793.2	793.5	831.7	828.2	823.0
Mean Barometric Pressure, inHg	30.10	30.10	30.10		30.10	30.08	30.08
Mean RH%	84.1	86.6	83.6		76.3	72.0	69.4
Mean Temp, °F	75.6	77.1	80.7		84.7	87.3	79.4
Abs. humid (lb water/lb dryair)							
F factor, SCF/MMBtu HHV	8482	8482	8482		8482	8482	8482
HHV Btu/SCF nat. gas	1021	1021	1021		1021	1021	1021
LHV Btu/SCF nat. gas	920	920	920		920	920	920
Stack temperature, F	242	243	241		247	243	245
Stack pressure, inHg	30.06	30.05	30.05		30.04	30.02	30.02
Stack moisture, %	7.5	7.5	7.5		8.6	8.6	8.6
O_2, %dry	15.20	15.20	15.20		15.36	14.73	14.77
CO_2, %dry	3.25	3.26	3.25		3.15	3.53	3.56
Stack actual flow rate, ACFM	735011	711313	714620		787808	762808	766264
Stack standard flow rate, SCFMD	514105	496453	499778		539741	524887	526348
Particulate total catch, mg	N/A	N/A	N/A		N/A	N/A	N/A
Volume sampled, SCFD	N/A	N/A	N/A		N/A	N/A	N/A
Particulate, lbs/MMBtu, HHV	N/A	N/A	N/A		N/A	N/A	N/A
Particulate, lbs/MMBtu, LHV	N/A	N/A	N/A		N/A	N/A	N/A
Particulate, lbs/hr	N/A	N/A	N/A		N/A	N/A	N/A
NOx, ppmvd	10.95	10.55	10.31	10.60	10.29	12.75	14.34
NOx, ppmvd 15%O_2, ISO	12.99	12.71	12.76	12.82	13.15	N/A	N/A
NOx, lbs/MMBtu HHV	0.04066	0.03917	0.03828	0.0394	0.03931	0.04373	0.04951
NOx, lbs/MMBtu LHV	0.04512	0.04347	0.04248	0.0437	0.04363	0.04854	0.05495
NOx, lbs/hr	40.33	37.52	36.91	38.3	39.78	47.94	54.07
CO, ppmvd	0.07	0.07	0	0.0467	0	0.1	0.09
CO, lbs/MMBtu HHV	0.00016	0.00016	0.00000	0.00011	0.00000	0.00021	0.00019
CO, lbs/MMBtu LHV	0.00018	0.00018	0.00000	0.00012	0.00000	0.00023	0.00021
CO, lbs/hr	0.16	0.15	0.00	0.10	0.00	0.23	0.21

Fuel Analyses

On each of the four test days two grab samples of natural gas entering the plant were taken from the supply pipeline. One sample was analyzed for the main constituents in order to calculate lower and higher heating values as well as F-factors. The second sample was analyzed for sulfur content. The laboratory reported results are given at Tab 12 of Part B. In summary:

Table 8. Pipeline Natural Gas Fuel Constants

Date	Btu/SCF HHV	Btu/SCF LHV	Sulfur wt%	Fd*
10/12	1021	920	0.0051	8482
10/13	1020	919	0.0032	8481
10/14	1018	918	0.0029	8480
10/15	1021	920	0.0026	8482

* DSCF flue gas / MMBtu at 0% excess air

Detailed Performance Specification Test Results for the NOx Continuous Emission Monitoring System

Relative Accuracy

The relative accuracy of the NOx analyzer and NOx continuous emission rate monitoring system were calculated from reference method test results reported in Tables 5, 6, and 7 and the average of the NOx values (ppmw, and lbs/hr) reported by the CEMS during each test run. In the following table the relative accuracy is calculated based on 11 paired runs. The CEMS values are the average of 1-minute values reported by the CEMS over the interval stated in the table (see Part B, Tab 13).

Table 9. Relative Accuracy of NOx CEMS

RATA Run No.	RATA Date,Time	CEM NOx lbs/hr	RM* NOx lbs/hr	Difference	CEM NOx ppmw	RM* NOx ppmw	Difference
1	10/14, 11:03-14:03	35.34	35.22	0.12	8.98	9.15	-0.17
2	10/14, 12:22-13:20	35.93	34.34	1.59	8.87	8.98	-0.11
3	10/14, 14:07-15:06	33.90	34.18	-0.28	8.72	8.96	-0.24
4	10/14, 15:39-16:28	33.13	33.83	-0.70	8.62	8.91	-0.29
5	10/14, 16:26-17:26	32.22	32.20	0.02	8.41	8.55	-0.14
6	10/15, 07:43-08:35	38.82	40.33	-1.51	9.77	10.13	-0.36
7	10/15, 09:06-09:50	37.81	37.52	0.29	9.52	9.76	-0.24
8	10/15, 10:15-11:11	36.35	36.91	-0.56	9.20	9.54	-0.34
9	10/15, 11:28-12:27	40.45	39.78	0.67	9.50	9.41	0.09
10	10/15, 13:29-14:30	47.98	47.94	0.04	11.20	11.65	-0.45
11	10/15, 16:47-17:22	55.08	54.07	1.01	12.76	13.11	-0.35
	*Reference Method Average		38.76	0.0627		9.83	-0.2347
	Standard Deviation			0.8495			0.1511
	$t_{(.975)}$			2.228			2.228
	Confidence Interval			0.571			0.102
	Relative Accuracy%			1.63			3.42

Calibration Drift Test

Calibration drift tests were conducted on the NOx CEMS over a seven day period during which the plant was operating above 50% of its rated capacity. During the drift test period no maintenance was performed or adjustments made to the emission monitoring system. High and low level calibration gases (EPA Protocol No. 1) were injected at 24-hour intervals and the CEMS response recorded (see Part B, Tab 13). The low-level gas used was zero air while the high level gas was NO in a blend of CO_2 and nitrogen. As the results in Table 10 show, the maximum calibration drift was well below the maximum allowable of 2.5% of span.

Table 10. NOx CEMS Calibration Drift Test Results

Date/time	Reference Value (R)	Monitor Response (A)	Absolute Difference |R-A|	Calibration Error % |R-A|·100/S *
10/12, 07:16	23.90 ppm	23.95	0.05	0.20 %
10/13, 05:45	23.90 ppm	23.91	0.01	0.04 %
10/14, 05:45	23.90 ppm	23.90	0.00	0.00 %
10/15, 05:45	23.90 ppm	23.84	0.06	0.24 %
10/16, 05:45	23.90 ppm	23.70	0.20	0.80 %
10/17, 05:45	23.90 ppm	23.70	0.20	0.80 %
10/18, 05:45	23.90 ppm	23.85	0.05	0.20 %
10/19, 05:45	23.90 ppm	23.84	0.06	0.24 %
			Maximum	0.80 %
10/12, 07:30	0.00 ppm	0.01	0.01	0.04 %
10/13, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/14, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/15, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/16, 06:00	0.00 ppm	0.02	0.02	0.08 %
10/17, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/18, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/19, 06:00	0.00 ppm	0.01	0.01	0.04 %
			Maximum	0.08 %

* The NOx analyzer span (S) is 25 ppm NOx.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
GAINESVILLE, FL 32605

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	January 5, 1994			$250.00

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Bureau of
Air Regulation

KBN Engineering and Applied Sciences, Inc.
GENERAL DISBURSEMENT ACCOUNT
PH. 904-331-9000
1034 N.W. 57TH STREET
GAINESVILLE, FL 32605

First Union National Bank of Florida
Gainesville, Florida 32605

63-2/630
Branch 311

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January 5 1994

PAY ***250*** **DOLLARS AND** **00** **CENTS** $ ***250.00**

TO THE ORDER OF Florida Department of Environmental Protection

KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

⑈010925⑈ ⑆063000021⑆ 2131100925716⑈

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

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SEP 21 1993

Division of Air
Resources Management

DEPARTMENT OF ENVIRONMENTAL PROTECTION

SEP 20 1993

OFFICE OF THE SECRETARY

SEP 17 1993

4APT-AE

Mr. Clair H. Fancy, Chief
Air Resources Management Division
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

RE: Orlando CoGen Limited, L.P. (OCL)
Stationary Gas Turbines, AC 48-206720, PSD-FL-184
Customized Fuel Monitoring Schedule

Dear Mr. Fancy:

This letter is in response to OCL's July 26, 1993, request for approval of a customized fuel monitoring schedule for the above referenced project. This request was sent to the Environmental Protection Agency (EPA), and a copy was forwarded to you. Since the authority for approving alternatives to the monitoring requirements in § 60.334(b) of 40 CFR Part 60, Subpart GG, was not delegated to the State of Florida, we have reviewed OCL's custom fuel monitoring schedule. Based on our review, we have determined that it is acceptable because it conforms to custom fuel monitoring guidance (a copy of this guidance memo is enclosed) issued by EPA Headquarters in 1987. Therefore, you may modify OCL's permit accordingly. Please note that the approved reference methods are cited in 40 CFR §60.335(d), and not in 40 CFR §60.335(b)(2) as referenced in OCL's July 26, 1993, letter.

If you have any questions regarding the determination provided in this letter, please contact Mr. Mirza P. Baig of my staff at 404/347-5014.

Sincerely yours,

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

Enclosure

cc: Mr. Tom Hess, Orlando CoGen Limited, L.P.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG 14 1987

OFFICE OF
AIR AND RADIATI

MEMORANDUM

SUBJECT: Authority for Approval of Custom Fuel Monitoring Schedules Under NSPS Subpart GG

FROM: John B. Rasnic, Chief
Compliance Monitoring Branch

TO: Air Compliance Branch Chiefs
Regions II, III, IV, V, VI and IX

Air Programs Branch Chiefs
Regions I-X

The NSPS for Stationary Gas Turbines (Subpart GG) at 40 CFR 60.334(b)(2) allows for the development of custom fuel monitoring schedules as an alternative to daily monitoring of the sulfur and nitrogen content of fuel fired in the turbines. Regional Offices have been forwarding custom fuel monitoring schedules to the Stationary Source Compliance Division (SSCD) for consideration since it was understood that authority for approval of these schedules was not delegated to the Regions. However, in consultation with the Emission Standards and Engineering Division, it has been determined that the Regional Offices do have the authority to approve Subpart GG custom fuel monitoring schedules. Therefore it is no longer necessary to forward these requests to Headquarters for approval.

Over the past few years, SSCD has issued over twenty custom schedules for sources using pipeline quality natural gas. In order to maintain national consistency, we recommend that any schedules Regional Offices issue for natural gas be no less stringent than the following: sulfur monitoring should

Enclosure

Conditions for Custom Fuel Sampling Schedule for Stationary Gas Turbines

1. Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

2. Sulfur Monitoring

   a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2).

   b. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

   c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample anaylsis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

   d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the State Air Control Board) of such excess emissions and the custom schedule shall be re-examined by the Environmental Protection Agency. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the State of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be available for inspection by personnel of federal, state,and local air pollution control agencies.

be bimonthly, followed by quarterly, then semiannual, given at least six months of data demonstrating little variability in sulfur content and compliance with §60.333 at each monitoring frequency; nitrogen monitoring can be waived for pipeline quality natural gas, since there is no fuel-bound nitrogen and since the free nitrogen does not contribute appreciably to NO_x emissions. Please see the attached sample custom schedule for details. Given the increasing trend in the use of pipeline quality natural gas, we are investigating the possibility of amending Subpart GG to allow for less frequent sulfur monitoring and a waiver of nitrogen monitoring requirements where natural gas is used.

Where sources using oil request custom fuel monitoring schedules, Regional Offices are encouraged to contact SSCD for consultation on the appropriate fuel monitoring schedule. However, Regions are not required to send the request itself to SSCD for approval.

If you have any questions, please contact Sally M. Farrell at FTS 382-2875.

Attachment

cc: John Crenshaw
George Walsh
Robert Ajax
Earl Salo

CMR P 649 682 993
7-27-93
Lehigh Valley, PA

Orlando CoGen Limited, L.P.

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

26 July 1993

RECEIVED
JUL 30 1993
Division of Air Resources Management

Mr. C. H. Fancy, P.E.
Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Orlando CoGen (I), Inc.
129-MW Combined Cycle Gas Turbine, Orange County
AC 48-206720
PSD-FL-184

Dear Mr. Fancy:

We would like to inform the Department that in accordance with Rule 17-2.660, F.A.C., that the anticipated date of initial startup of this facility is 1 September 1993. We will notify the Department of the date of actual startup within 15 days after that date. For your information, at this time we tentatively plan to perform the emission testing required by the referenced permit beginning on or about 15 September, however we will notify the department 30 days prior to the actual anticipated date.

Please call me at (215) 481-7620 with any questions or comments.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

cc: Mr. Charles Collins, P.E.
Central District

Mr. Dennis J. Nester
Orange County Environmental
Protection Department
J. Harper, EPA
J. Bunyak, NPS

Fed Ex: 0181-0342-7
7-7-93
Allentown, PA

Orlando CoGen Limited, L.P.

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

7 July 1993

Mr. Dennis J. Nester
Environmental Engineer
Orange County Environmental Protection Department
2002 E. Michigan St.
Orlando, FL 32806

RECEIVED

JUL 08 1993

Division of Air
Resources Management

Subject: Orlando CoGen Limited, L.P. (OCL)
AC 48-206720
PSD-FL-184
Emission testing

Dear Mr. Nester:

I was happy to get a chance to talk to you last week about the impending startup of our plant in September. As we discussed, fairly extensive emission testing will be conducted to meet the specific requirements of the referenced construction permit, other Florida DER regulations, and new source performance standards. Also, because this plant is equipped with a continuous emission monitoring system, a number of emission monitoring system performance specification tests, including relative accuracy, will be conducted. The monitoring system performance tests will have to meet both 40 CFR 60 and 40 CFR 75 specifications.

As promised, I have enclosed a few attachments that may be of help to you prior to our meeting next Thursday in understanding the plant and our proposed program to conduct needed emissions testing . These are:

A) A brief description of the combined cycle power plant combustion equipment and the continuous emission monitoring system.

B) A proposed plan for emission testing to demonstrate both emission compliance and to confirm that the emission monitoring system meets performance specifications. The table on page B-6 summarizes the tests and the number runs that we believe will be needed at different plant operating conditions.

C) This attachment shows three detailed sections of mechanical drawings locating the point of emission testing and test port configuration.

Stack Testing

As noted in the draft test plan (Attachment B) we are proposing some very minor modifications to the sampling points suggested by Method 20 (NOx). Method 20 requires a sampling site as close to the turbine exhaust as practical considering turbine geometry, baffling, and point of introduction of dilution air. Referring to the figure on page A-1, at this facility the exhaust of the gas turbine enters a transition duct containing duct burners before it enters the steam generator. Testing in the transition duct or in the steam generator is not practical or meaningful for the following reasons (many of which Method 20 recognizes):

- In the transition duct it is highly likely that cyclonic flow is present from the turbine exhaust and at the same time the duct cross section is continually changing. This would likely lead to errors in flow measurement (the DER permit is based on mass flow rate of NOx and therefore velocity traverses are needed).

- Duct burners immediately following the turbine would interfere with test probe traverses here and the location presents potential danger to the test team because of the high temperature exhaust (no dilution air is used in this plant).

- In the steam generator, the multitude of tube bundles for heat transfer would again interfere with test probe traverses and also again would interfere with accurate determination of gas velocity. Also the size of the cross sectional area would represent difficulty in testing (roughly 22 by 48 feet)

- The proposed test location, at the stack, is more accessible and more likely to be representative. Because the only air entering the process is combustion air in the turbine (no dilution air down stream of the exhaust is injected) the flue gas at the proposed stack test location is the same composition as the turbine exhaust. The flue gas velocity should be more uniform and the stack cross section more manageable to test (9 x 21.5 feet).

- Continuous emission compliance for the facility is based on meeting a total emission rate of 69.6 lbs/hr (combined duct burner and combustion turbine firing) leaving the stack (DER condition 13) . On a continuous basis there is no separate emission requirement for the duct burner and the combustion turbine. Thus the emission point of concern is the stack not the turbine or duct burners individually.

- For the purposes of initial and annual compliance testing, the stack location can meet DER permit requirement for determining turbine and duct burner emissions separately by simply performing the tests with and without duct burner firing. This is proposed in the draft test plan.

- The proposed test location and facilities meet the requirements of EPA Method 1 and DER 17-2.700 (4)(c) relating to test facilities. It is problematic that any other location in the plant would meet these criteria. Further, the turbulent mixing that the flue gas experiences in the steam generator should minimize the chances for stratification at this test point compared to others.

- Actual traverse points for gas emissions (CO, NOx, etc.) would be selected based on the criteria of Method 20 (i.e. 8 points having the lowest O_2 or highest CO_2) unless there are no significant differences among the points. In that case we would propose to use fewer points for each traverse.

We would also like to review with you the county's reporting and notification requirements. This includes items such as:

- frequency, content, and format of routine reports, both emissions and process data
- notification procedures: for excess emission incidents, monitoring system out of service periods, annual compliance tests
- requirements for stack test contractors such as registration or certification.

I appreciate your time in reviewing the enclosed material and would be happy to answer any questions or provide additional information that would be helpful to you. Please call me at (215) 481-7620 (fax: 5444). I look forward to meeting you next Thursday (15 July) at your office at 8:00 AM.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

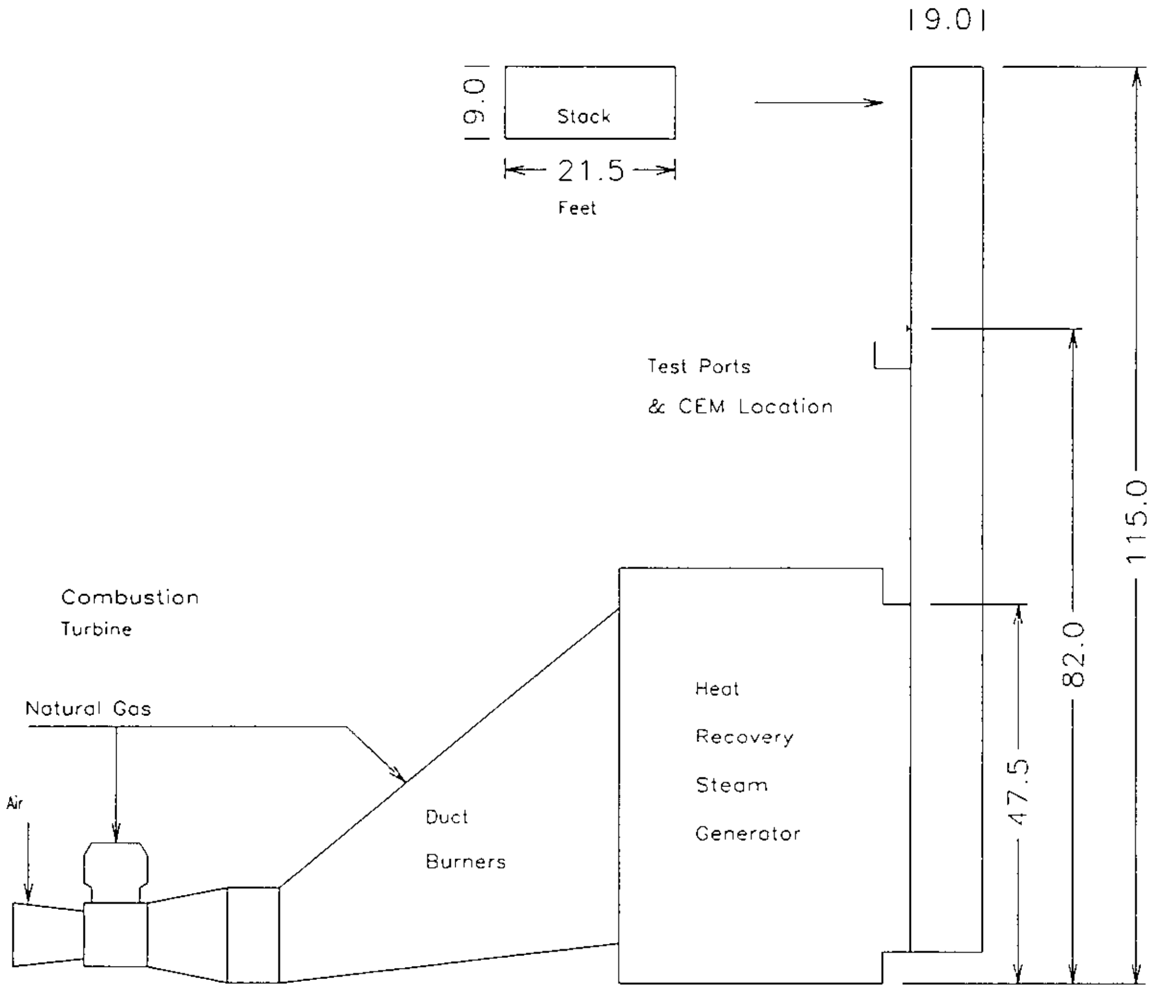
cc: Mr. Gary Kuberski
Central District Office, Florida DER

Mr. Bruce Mitchell
Permitting and Standards, Florida DER

Orlando CoGen Limited-Continuous Emission Monitoring System

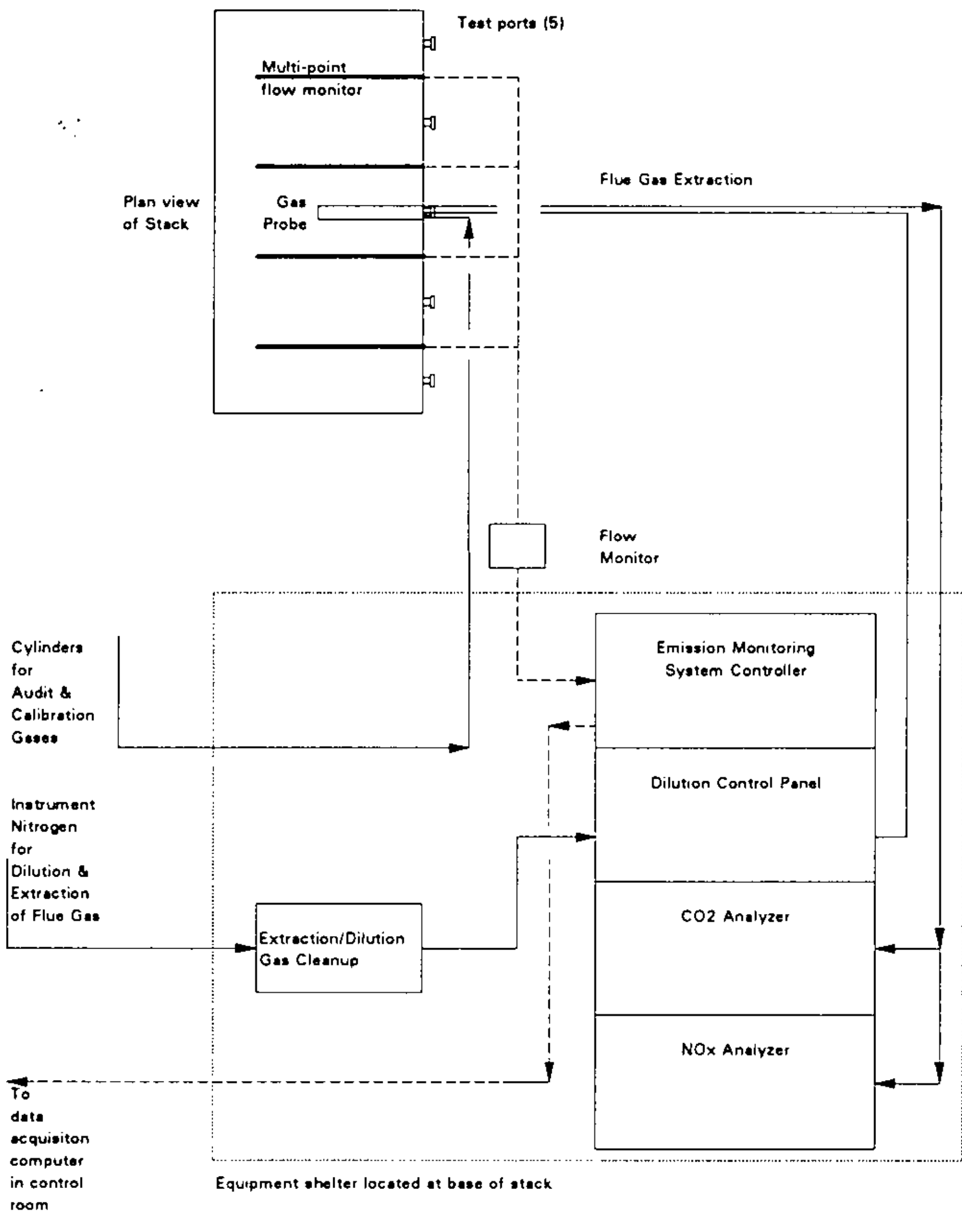
Process Description

The Orlando CoGen Limited facility generates process steam and electricity in a combined cycle power plant consisting of a combustion turbine (CT) followed by a heat recovery steam generator (HRSG) as shown in the figure below. Additional gas may be fired in duct burners (DB) when additional steam is needed. However, even with DB firing, the only point of combustion air addition is at the combustion turbine. When there is no DB firing, the flue gas monitored at the stack is at the same concentration as at the outlet of the combustion turbine. When firing additional fuel in the duct burners, the stack gas emissions are the combination of those produced by the CT and the duct burners. Again, no additional combustion air is needed at the duct burners when they are fired. The turbine exhaust, because of the high excess air fired in the turbine, contains more than enough oxygen (on the order of 15%) to supply that needed to cleanly burn the supplementary fuel fired in the duct burners.



Emission Monitoring System

As shown in the following diagram, the continuous emission monitoring system (CEMS) measures the concentrations of NOx, CO_2, and the flow rate of flue gas leaving the stack following the HRSG. Flue gas is extracted from the stack using purified nitrogen to carry it to CO_2 and NOx analyzers housed in an air conditioned shelter at the base of the stack. The dry nitrogen carrier gas, by diluting the sample, lowers its dew point enough that no moisture removal is necessary prior to passing the gas sample to the analyzers. Because no moisture is removed in the sampling process, all concentrations are therefore on a wet basis.



Flue gas flow rate is monitored at multiple points in the plane of the stack using differential pressure. The multi-point readings are integrated and compensated for temperature and pressure to produce a flow rate in standard cubic feet per minute.

Other components of the system are:

- A system controller which takes instrument readings and converts the analyzer outputs into the correct signal for transmission to the data acquisition computer. The controller also controls the injection of reference gases for system calibration and auditing.

- The dilution control panel controls the flow of extraction gas to the gas sample probe in the stack.

- The extraction gas cleanup module removes moisture, NOx, and CO_2 which may be present in the nitrogen carrier used to extract flue gas from the stack.

Data Acquisition

Data from the analyzers is transmitted via the system controller to a dedicated microcomputer which logs the measurement data (ppm NOx, %CO_2, and SCFM flow) and performs calculations to convert the measurements to other units, such as lbs/hr, and lbs/MMBtu. Additional functions include:

- tracking cumulative emissions,
- recording results of daily and quarterly cylinder gas checks and audits of the CEMS,
- producing alarms if permitted emissions are exceeded or monitor malfunctions are detected,
- recording status of the monitoring system,
- and producing emission reports required by permits and regulations.

Orlando CoGen Limited

DRAFT Plan for Atmospheric Emission Testing and Performance Testing of the Continuous Emission Monitoring System

I. Term definitions

DER	Florida Department of Environmental Regulation
CEMS	Flue gas continuous emission monitoring system including all gas analyzers, computer data acquisition system, and gas sampling components
CT	Combustion turbine
DB	Duct burner
PST	Performance specification test (for CEMS)
PM	Particulate matter
RA	Relative accuracy, deviation of a CEMS measured value from a reference method measured value
RM	Reference method, a test method approved by EPA or DER
CD/CE	Calibration drift/calibration error, change over a time in a CEMS monitor's response to a reference gas
Part 52/60/75	Refers to Title 40 of the Code of Federal Regulations; Parts 52, 60, 75
Bias	Test for systematic error in CEM measurements with respect to the RM measurements
HRSG	Heat recovery steam generator
Db	EPA new source performance standards relating to the duct burner
GG	EPA new source performance standards relating to the combustion turbine
ISO	ISO standard day refers to ambient atmospheric conditions of 59°F, 60% RH, and 1 atm pressure
Protocol Gas	A calibration gas meeting EPA traceability requirements to a reference material
DAS	Data acquisition system component of the CEMS

II. Purpose of test program

1) To demonstrate compliance with the emission limitations contained in the following:

a) Florida DER Permit

NOx	CT	15 ppmvd @ 15% O_2 (at ISO**)	57.4 lbs/hr
	DB	0.1 lb/MMBtu *	12.2 lbs/hr
CO	CT	10 ppmvd @ 15% O_2	22.3 lbs/hr
	DB	0.1 lb/MMBtu *	12.2 lbs/hr
PM/PM-10	CT	0.01 lb/MMBtu *	9.0 lbs/hr
	DB	0.01 lb/MMBtu *	1.2 lbs/hr
VOC	VOC is deemed to meet permit conditions if CO emission limitations are met		
Visual emissions	CT/DB	<10% opacity	

* lower heating value basis
maximum heat input to the CT 856.9 MMBtu/hr (**LHV**) (ISO day){**see Appendix**}
maximum heat input to the DB 122.0 MMBtu/hr (**LHV**) (3688 hour annual average)

b) 40 CFR 60 Subpart Db (duct burner emissions) — NOx - 0.20 lbs/MMBtu (**HHV**)

c) 40 CFR 60 Subpart GG (combustion turbine emissions) — NOx - 93 ppmvd @ 15% O_2 (ISO)[60.332]
SO_2 - either <150 ppmvd @ 15% O_2 or fire fuel containing <0.8% sulfur by weight [60.335 (d)(e)]

**NOx measurement correction equation to ISO standard day conditions:

$$NOx_{(ISO-ppmvd-15\%O_2)} = NOx_{(obsv'd-ppmvd-15\%O_2)} \cdot \left(\frac{P_r}{P_o}\right)^{0.5} \cdot e^{19(H_o-0.00633)} \cdot \left(\frac{288° K}{T_a}\right)^{1.53}$$

P_r-reference combustor inlet absolute pressure at 101.3 KPa ambient pressure
P_o-observed combustor inlet absolute pressure at test
H_o-observed humidity of ambient air
T_a-ambient temperature, °K

2) To demonstrate that the CEMS meets the performance specifications contained in:

a) 40 CFR 60 Appendix B: Specification 2 for NOx monitoring
Specification 3 for CO_2 monitoring
Specification 6 for continuous emission rate monitoring

b) 40 CFR 75 Appendix A NOx, CO_2, and flow monitoring specifications

III. Test Location and Number of Tests

All emission testing will take place at the stack serving the heat recovery steam generator. The stack is rectangular with dimensions of 9 by 21.5 feet with the long side containing five 4-inch test ports. Testing facilities including platforms, platform access, electrical power, and test equipment supports meeting DER requirements will be provided.

The equivalent diameter of this stack is 12.7 feet. Using this equivalent diameter the test ports are 2.72 diameters downstream of the last flow disturbance and more than two diameters upstream of the stack exit. Based on RM 1, the minimum number of traverse points for particulate tests is 25 on a 5 x 5 grid. For flow rate determinations, the number of traverse points may be reduced to 16. However, given the 5 ports, in practice a minimum of 20 points will be needed for all tests requiring flow rate determinations.

With respect to combustion turbine tests required by subpart GG, this location is the closest practical point to conduct required emission tests. The transition from the CT exhaust to the HRSG varies continuously in cross section and contains the duct burners making it impractical to conduct tests between the combustion turbine and duct burners. Instead of simultaneously testing the combustion turbine exhaust and stack (Db), test runs will be conducted at the stack without duct burner firing and then with duct burner firing while maintaining combustion turbine operation constant. Because no dilution air is added in the HRSG, measurements at the stack should be representative of the conditions at the CT outlet when the DB is not being fired.

Summary of On Site Tests

Test	Number of Test Runs
Particulate Matter	6
NOx	15
CO_2	15
CO	6
Visual Emissions	6
Flow	27
Additional required for CEMS	Drift/Linearity/Response

IV. Reference Method Test Requirements for Emission Compliance Determination and CEMS Performance Specification Testing.

Emis-sion	Reg.	Ref. Method	Plant Condition During Test	Traverse Pts/No. Runs	Sampling Time	Other Requirements & Exceptions
PM	DER Permit only	EPA-5 [Permit condition 7.a.]	within 10% of maximum heat rate input at ambient conditions (interpreted to mean maximum CT firing at ambient conditions with and without maximum DB firing) [Permit Condition 11].	Minimum of 6 valid tests. Number of traverse points from EPA-1 (i.e., 25 points) each test run).	Minimum of 2 minutes per traverse point with sample time per run ≥ 1 hr & gas volume of >25 SCF [DER 17-2.700 (1)(d)1.a.].	Will perform 3 test runs with and 3 test runs without DB firing while maintaining CT at maximum operating rate.
NOx	DER Permit	EPA-20 [Permit condition 7.d.]	as for particulate	Minimum of 6 valid tests. At the 8 traverse points having the highest CO_2 at the low CT operating rate.	as above.	For determination of 8 sample points, method requires diluent sampling at 49 points on 7 x 7 grid [60, App. A, RM 20, 6.1.2.1] at turbine exhaust.Propose use RM 1 grid for initial diluent sampling to select 8 traverse points at stack.
	Db	EPA-20	as for particulate	6 tests (see last column), otherwise as above.	Minimum of 1-minute plus RM response time at each of the 8 points.[60 App. A. 6.2.2]	Db requires simultaneous measurement at outlet of CT and HRSG stack[60.46b(f)]. Propose 3 test runs with and 3 test runs without maximum DB firing while maintaining CT at maximum operating rate.
	GG	EPA-20	Test at 4 CT operating rates required. Operating points are minimum, maximum and 2 intermediate points. [60 335(c)(2&3)]	3 valid tests at each of the 4 operating points. Traverse points for each test as above [60, App. A, RM 20,6.2]	Minimum of 1-minute plus RM response time at each of the 8 points.[60 App. A. 6.2.2]	Maximum operating rate point tests are satisfied by above tests. Require an additional 9 tests at intermediate and low operating rates without DB firing.
	PST (for RA of CEM)	EPA-20	Operating rate >50% [60, App.B, Spec 2,5.3]	Minimum of 9 valid tests required. 15 tests should be available provided requirements at right are met.	Requires at least 3 traverse points sampled for 7 minutes each (21 minutes total/run)[60,App B,Spec.2,7.1.1]	Will conduct RM 20 for Db and GG tests above such that a minimum of 21 minutes of sampling occurs for each test run. Provided this requirement is met, the data from those tests may be used to satisfy this requirement.
CO_2	PST only	EPA-20	as above	as above	as above	as above
CO	DER Permit only	EPA-10 [Permit condition 7.b.]	same as for PM tests	6 valid tests using the 8 NOx sample points above for each test.	Minimum of 2 minutes per traverse point with sample time per run ≥ 1 hr & gas volume of >25 SCF [DER 17-2.700 (1)(d)1.a.].	Will perform 3 test runs with and 3 test runs without DB firing while maintaining CT at maximum operating rate.
Opac-ity	DER Permit only	EPA-9	same as for PM tests	6 valid observations	60 min/per observation period [DER 17-2.700 (1)(d)1.b]	as above

In addition to the pollutant reference method tests above, EPA RM 2, 3, and 4 will be used to determine flue gas flow rates, dry molecular weight, and flue gas moisture as needed.

V. CEMS Performance Specifications and Test Requirements *

	40 CFR Part 60		40 CFR Part 75	
	Standard	Test Method	Standard	Test Method
Linearity: NOx CO_2	N/A N/A		NOx-measured deviations from calibration gases must be <5% of the calibration gas value or 5 ppm absolute difference. CO_2-all measurements, less restrictive of 5% of: the calibration gas value, absolute difference of 0.5% CO_2	Challenge system by introducing calibration gases at point of sample acquisition at three concentration levels (low-, mid- high-). Repeat three times with no concentration used twice in succession [75,App.A,6.2]
Calibration error (drift): NOx CO_2 flow	NOx-deviations from zero and high-level calibration gases must be <2.5% of instrument span.[60,App.B,Spec.2,4.2] CO_2-same as Part 75 [60,App.B,Spec.2,2.2] Flow-same as Part 75 [Part 52 App.E ,4]	NOx-same as Part 75 CO_2-same as Part 75 Flow-same as Part 75	NOx-deviations from the zero and high-level calibration gases must be <2.5% of instrument span or <5 ppm absolute deviation. CO_2-deviation from the zero and high-level calibration gases, absolute difference must be <0.5% CO_2. Flow-deviation must be <3% of monitor span at two reference points: 0-20% of span and 50-70% of span	NOx, CO_2-over a 7 consecutive operating day period, measure the calibration error for each monitor at approximately 24-hr intervals for the zero-level and high-level. Challenge each monitor with the zero and high-level gas once by injecting the gas at the point of sample acquisition.[75, App.A,6.3.1] Flow-inject reference signal to the flow transducer at two test points once each day over the 7-day period.[75, App.A,6.3.2]
Cycle time /response test: NOx/CO_2 combined	N/A	N/A	Time to reach 95% of final response to a step change in CO_2 and NOx concentration must be <15 minutes[75, App.A,3.5]	While the CEMS is monitoring emissions, simultaneously challenge the CO_2 monitor and NOx monitor at two points (low level, high level) and record the time for the monitors to reach 95% of their final values. The system should be returned to normal operation between tests. Because this test is to observe responses to step changes in lbs NOx/MMBtu, the low level CO_2 calibration gas should be used simultaneously with the high level NOx calibration gas for one test and vice versa for the second test.[75, App.A,6.4]

Relative accuracy and bias: NOx CO_2 Flow	NOx-error in CEM measured relative to the RM measurements must be <20% (95% confidence) of the RM measurements or 10% of the applicable standard (whichever is greater) in units of the standards: lbs/MMBtu, ppm, lbs/hr. [60,App.B, Spec.2,4.3]	NOx, CO_2-same as Part 75 [60,App.B, Spec.2,7]	NOx-error in CEM measured lbs/MMBtu relative to the RM measurements must be <10% at 95% confidence of the RM measurements in lbs/MMBtu or if CEM mean value is <0.2 lb/MMBtu must be within ±0.02 lb/MMBtu of average RM. [75,App. A 3.3.2]	NOx, CO_2-at a normal operating rate perform a minimum of 9 valid RM tests (per PST 2 of Part 60) while simultaneously recording the CEM output during each test run. Calculate the relative accuracy at the 95% confidence level. [75,App. A 6.5.9]
	CO_2-error in CEM measured relative to the RM measurements must be <20% (95% confidence) of the RM measurements or 1% CO_2 (whichever is greater) [60,App.B, Spec.2,2.3]		CO_2-error in CEM measured %CO_2 relative to the RM measurements must be <10% of the RM at 95% confidence, or the difference between the average of the RM and the average of the CEM must be <±1% CO_2. [75,App.A,3.3.3]	
	Flow-N/A (Though 40 CFR Part 52 does contain flow monitor performance specifications, this part is not applicable to either a Subpart Db, or Subpart GG source)	Flow-N/A	Flow-error in SCFH measured must be <10% of the RM at 95% confidence for each operating level.	Flow-as above but perform at 3 plant operating rates with minimum of 9 RM flow tests at each plant operating level.
	Bias-N/A	Bias-N/A	Bias-shall not be biased low. For flow monitors, applies to only at intermediate operating rate.[75,App.A,3.4.]	Bias-use test results above in this calculation. The mean difference of the RM tests and the CEMS measurements must be less than the confidence coefficient.[75,App.A,7.6.4]

*Requirements for calibration gas ranges [Part 75, App. A, 5.2], all gases will be EPA Protocol 1 gases.

Zero-level concentration:	0-20% of instrument span
Low-level concentration	20-40% of instrument span
Mid-level concentration	50-60% of instrument span
High-level concentration	80-100% of instrument span

VI. Plant Data

During each emission test the following minimum process data will be recorded every 15 minutes (15 minute averages):

Natural gas flow to the combustion turbine
Natural gas flow to the duct burners
Steam production
Electric power generated
Combustion turbine-combustor inlet pressure

At least once during each test series the following ambient data will be recorded:

Barometric pressure
Temperature
Relative humidity

At least one fuel sample will be taken on each day of emission testing for analysis of sulfur and nitrogen and determination of lower and higher heating value using ASTM methods.

The CEMS DAS will record and report CEMS responses during tests for system RA, CD/zero drift, linearity, and response time.

VII. Tests Required at Each Plant Operating Level

The exact number and sequence of tests will be coordinated with the stack testing contractor and is subject to the availability of testing personnel and equipment. The CT operating points are to be determined prior to the submission of the the test plan to the Florida DER. This plan must be submitted at least 30 days prior to beginning emission and CEMS performance testing [DER Permit Cond. 11]. The final report of test results must be submitted to the DER within 45 days of completion of testing [DER Permit Cond. 11].

Test	Minimum CT Firing	CT Firing at Point 2	CT Firing at Point 3	Maximum CT Firing	Maximum CT & DB Firing
O_2 & CO_2	3 (PST)*	3 (PST)	3 (PST)	3 (PST)	3 (PST)
NOx	3(GG, PST)*	3 (GG, PST)	3 (GG, PST)	3 (DER 1-hr)	3 (DER 1-hr)
CO				3 (DER 1-hr)	3 (DER 1-hr)
PM				3 (DER1-hr)	3 (DER 1-hr)
Stack flow	9			9 (3 from PM)	9 (3 from PM)
Moisture	1	1	1	from PM	from PM
Dry MW	1	1	1	1	1
Visible emissions				3	3

* GG, PST means minimum sample time per run set by the longer of the two requirements

The number of test runs above should also be sufficient for the determination of CEMS RA. The CEMS drift test, linearity test, and response time test are performed using cylinder gases over a seven day period and do not require the presence of the test contractor.

Correction of observed combustion turbine firing rate at actual ambient conditions to firing rate at ISO ambient conditions.

$$Q_{iso} = \frac{Q_{obs}}{0.0253700 + \frac{12.8672}{v}}$$

where Q_{obs} is the natural gas firing rate in the combustion turbine in MMBtu/hr (LHV) and Q_{iso} is the value that would be observed under ISO conditions.

v is the moist volume of ambient air, ft^3 ambient air/lb dry air and is given by

$$v = \frac{\frac{29.92}{P} \cdot \left(\frac{379.4}{520} \cdot (T + 460) \right)}{28.97 \cdot \left(1 - \frac{P_w \cdot RH}{P} \right)}$$

and P_w is the vapor pressure of water given by

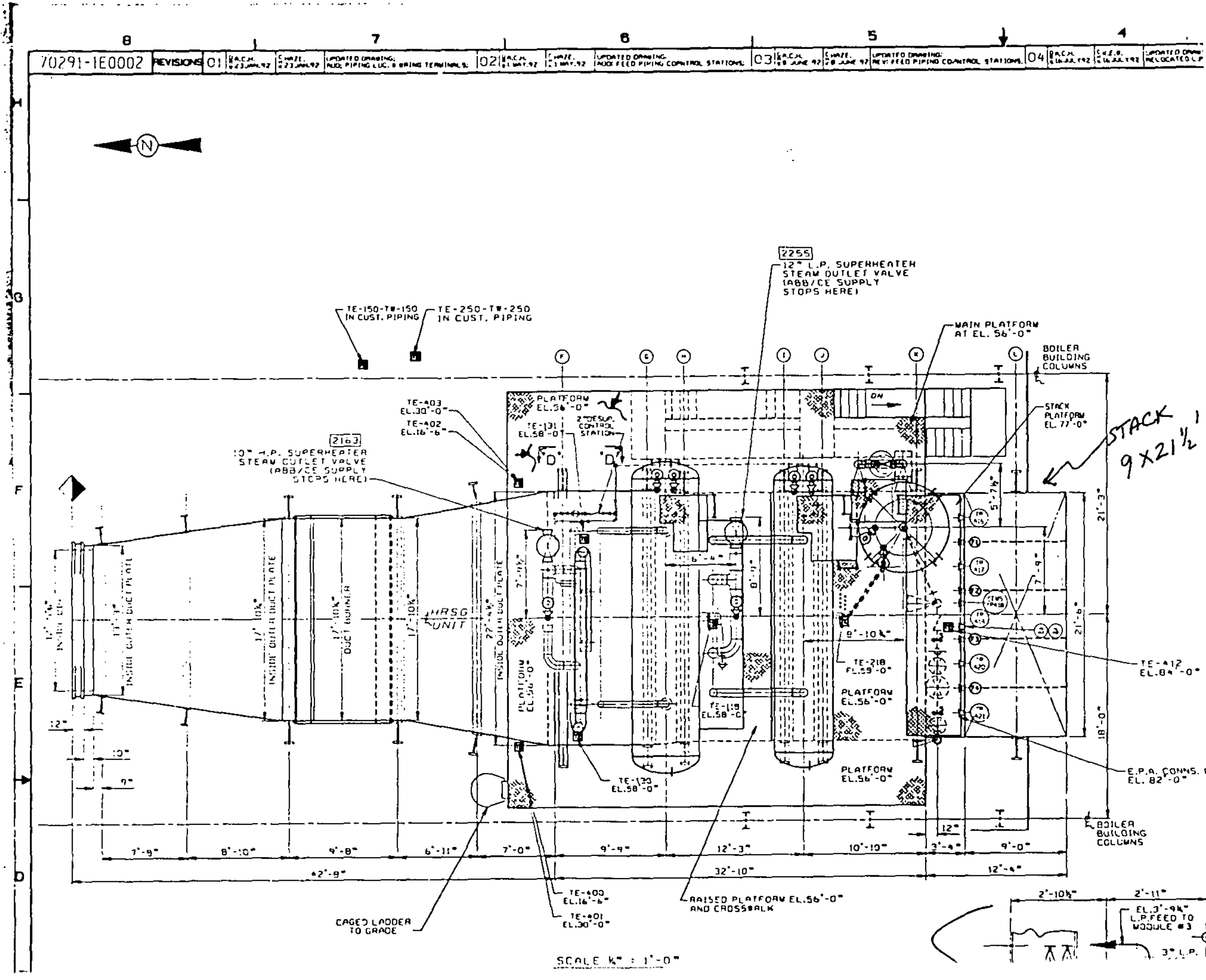
$$P_w = \exp \frac{37.2264 - 0.0691698 \cdot (T + 460)}{1 - 0.00578492 \cdot (T + 460)}$$

where **RH** is the ambient relative humidity (decimal fraction), T is ambient temperature (°F), and **P** is ambient pressure (inHg).

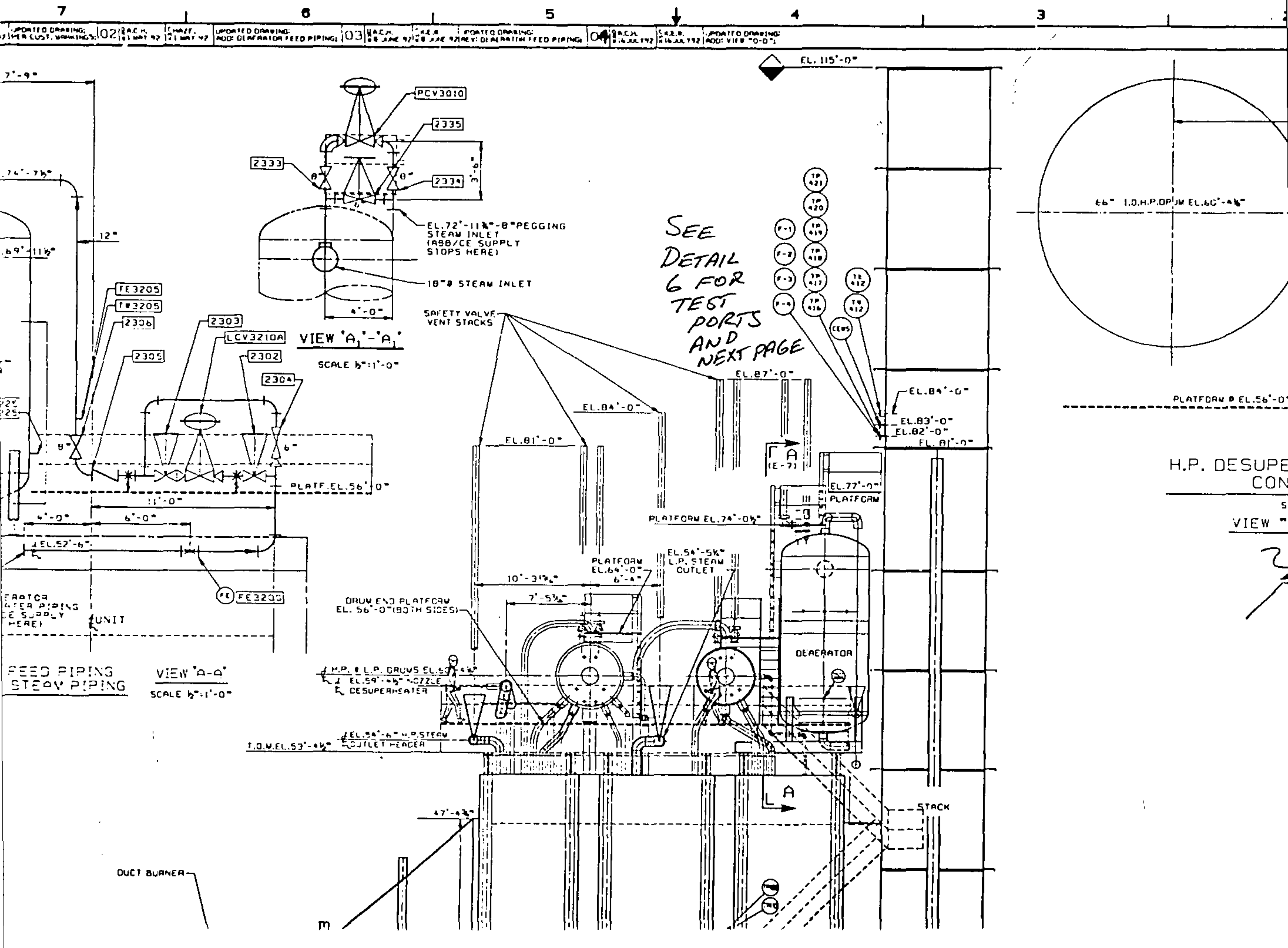
Orlando CoGen Limited

Attachment C

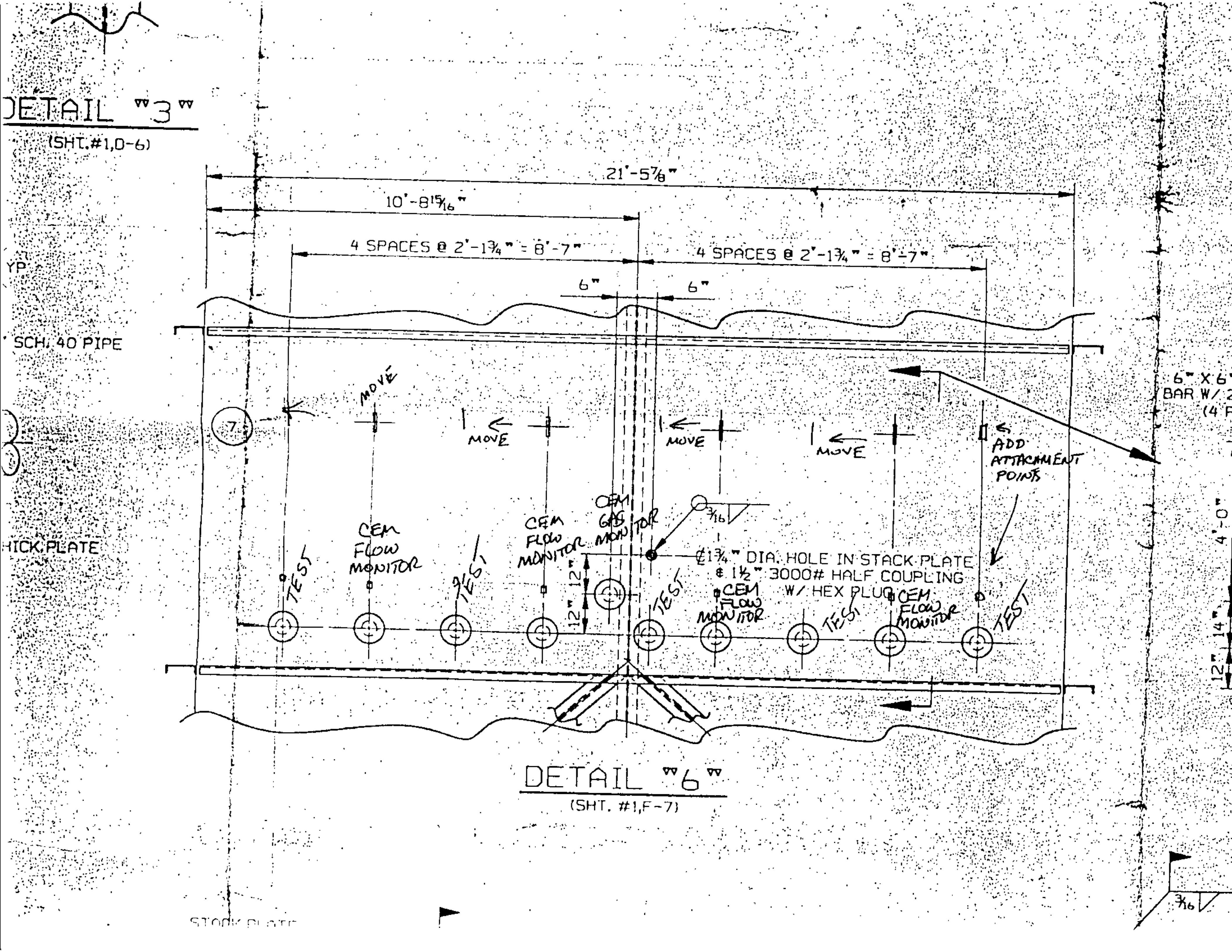
Plan view - heat recovery steam generator from turbine exhaust inlet to stack outlet
Partial elevation-heat recovery steam generator and stack
Detail of stack test ports and CEMS ports



70291-1E0002
REVISIONS
01 UPDATED DRAWING; ADD PIPING LOC. & WIRING TERMINALS
02 UPDATED DRAWING; ADD FEED PIPING CONTROL STATIONS
03 UPDATED DRAWING; REV. FEED PIPING CONTROL STATIONS
04 UPDATED DRAWING; RELOCATED L.P.
N
TE-150-TW-150 IN CUST. PIPING
TE-250-TW-250 IN CUST. PIPING
2255
12" L.P. SUPERHEATER STEAM OUTLET VALVE (ABB/CE SUPPLY STOPS HERE)
MAIN PLATFORM AT EL. 56'-0"
BOILER BUILDING COLUMNS
STACK PLATFORM EL. 77'-0"
STACK 9 X 21½'
PLATFORM EL. 56'-0"
TE-403 EL. 30'-0"
TE-402 EL. 16'-6"
TE-131 EL. 58'-0"
2" DESUP. CONTROL STATION
2163
10" H.P. SUPERHEATER STEAM OUTLET VALVE (ABB/CE SUPPLY STOPS HERE)
HRSG UNIT
INSIDE OUTER DUCT PLATE
DUCT BURNER
TE-218 EL. 59'-0"
TE-119 EL. 58'-0"
TE-130 EL. 58'-0"
TE-412 EL. 84'-0"
E.P.A. CONNS. EL. 82'-0"
TE-400 EL. 16'-6"
TE-401 EL. 30'-0"
CAGED LADDER TO GRADE
RAISED PLATFORM EL. 56'-0" AND CROSSWALK
7'-9" 8'-10" 9'-8" 6'-11" 7'-0" 9'-9" 12'-3" 10'-10" 3'-4" 9'-0"
42'-9" 32'-10" 12'-4"
21'-3" 21'-6" 18'-0"
EL. 3'-9¼" L.P. FEED TO MODULE #3
SCALE ⅛" = 1'-0"



UPDATED DRAWING: PER CUST. MARKINGS
02
UPDATED DRAWING: ADD: DEAERATOR FEED PIPING
03
UPDATED DRAWING: REV: DEAERATOR FEED PIPING
04
UPDATED DRAWING: ADD: VIEW "O-O"
EL. 115'-0"
PCV3010
2335
2333
2334
3'-6"
8"
EL.72'-11¾"-8"PEGGING
STEAM INLET
(ABB/CE SUPPLY
STOPS HERE)
18"Ø STEAM INLET
4'-0"
VIEW 'A1'-'A1'
SCALE ½"=1'-0"
SEE DETAIL 6 FOR TEST PORTS AND NEXT PAGE
SAFETY VALVE VENT STACKS
EL.87'-0"
EL.84'-0"
EL.81'-0"
EL.83'-0"
EL.82'-0"
EL.81'-0"
EL.77'-0"
PLATFORM
PLATFORM EL.74'-0½"
66" I.D.H.P.DRUM EL.60'-4½"
PLATFORM @ EL.56'-0"
H.P. DESUPE
CON
VIEW
7'-9"
12"
FE3205
TE3205
2306
2305
2303
LCV3210A
2302
2304
8"
6"
PLATF.EL.56'-0"
11'-0"
4'-0"
6'-0"
EL.52'-6"
FE3206
UNIT
FEED PIPING
STEAM PIPING
VIEW 'A-A'
SCALE ½"=1'-0"
PLATFORM EL.64'-0"
EL.54'-5½" L.P. STEAM OUTLET
10'-3¾"
7'-5¾"
6'-4"
DRUM END PLATFORM EL. 56'-0"(BOTH SIDES)
H.P. & L.P. DRUMS EL.59'-4½"
EL.59'-4½" NOZZLE
℄ DESUPERHEATER
EL.54'-6" H.P.STEAM OUTLET HEADER
T.O.M.EL.53'-4½"
DEAERATOR
A
(E-7)
A
47'-4½"
STACK
DUCT BURNER
m


DETAIL "3"
(SHT. #1,D-6)
YP
SCH. 40 PIPE
HICK PLATE
21'-5⅞"
10'-8 15/16"
4 SPACES @ 2'-1¾" = 8'-7"
4 SPACES @ 2'-1¾" = 8'-7"
6"
6"
7
MOVE
MOVE
MOVE
MOVE
ADD ATTACHMENT POINTS
CEM FLOW MONITOR
CEM FLOW MONITOR
CEM GAS MONITOR
CEM FLOW MONITOR
CEM FLOW MONITOR
TEST
TEST
TEST
TEST
TEST
3/16
12"
12"
⌀1¾" DIA. HOLE IN STACK PLATE
℄ 1½" 3000# HALF COUPLING
W/ HEX PLUG
6" X 6"
BAR W/ 2
(4 P
4'-0"
14"
12"
3/16
DETAIL "6"
(SHT. #1,F-7)
STACK PLATE

DEPARTMENT OF ENVIRONMENTAL REGULATION STATE OF FLORIDA

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 4, 1993

Mr. Tom Hess
Energy Systems
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Dear Mr. Hess:

Re: Orlando CoGen, Inc.
AC 48-206720 and PSD-FL-184

Thank you for the updated information regarding the Orlando CoGen project. I have been able to complete my assignment because of the data you sent. Again, many thanks for the response.

Sincerely,

R. Bruce Mitchell

R. Bruce Mitchell
Engineer IV
Bureau of Air Regulation

Reading File
C. Collins, CD } 1-4-93 BRM

Environmental/Energy Division
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501
Telephone (215) 481-4911

AIR PRODUCTS

18 December 1992

Mr. Bruce Mitchell
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Orlando CoGen (I), Inc.
129-MW Combined Cycle Gas Turbine, Orange County
AC 48-206720
PSD-FL-184

Dear Mr. Mitchell:

Enclosed is the process information we discussed in our telephone conversation this morning. Included are

1) An overall process flow diagram
2) Material balance keyed to the diagram
3) An elevation drawing of the ABB supplied heat recovery steam generator

I also wanted to confirm the information I gave you over the phone with regard to power production and steam production.

Electric Power Production (ISO conditions)

	Power Attributable to Combustion Turbine	Power Attributable to Steam Turbine	Total Electric Power Generated
with no supplemental firing in the HSRG	78.8 MW	35.7 MW	114.5 MW
with supplemental firing in the HSRG	78.8 MW	50.1 MW	128.9 MW

Gross Steam Production from the Heat Recovery Steam Generator

	High Pressure Steam	Low Pressure Steam
with no supplemental firing in the HSRG	274,000 lb/hr 1140 psi, 930°F	79,100 lb/hr 80 psi, 536°F
with supplemental firing in the HSRG	368,200 lb/hr 1290 psi, 932°F	66,500 lb/hr 100 psi, 563°F

I hope this material will be helpful. Please call me at (215) 481-7620 if you have any questions or require additional information.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

cc'd:
C. Collins, CD 1-4-93

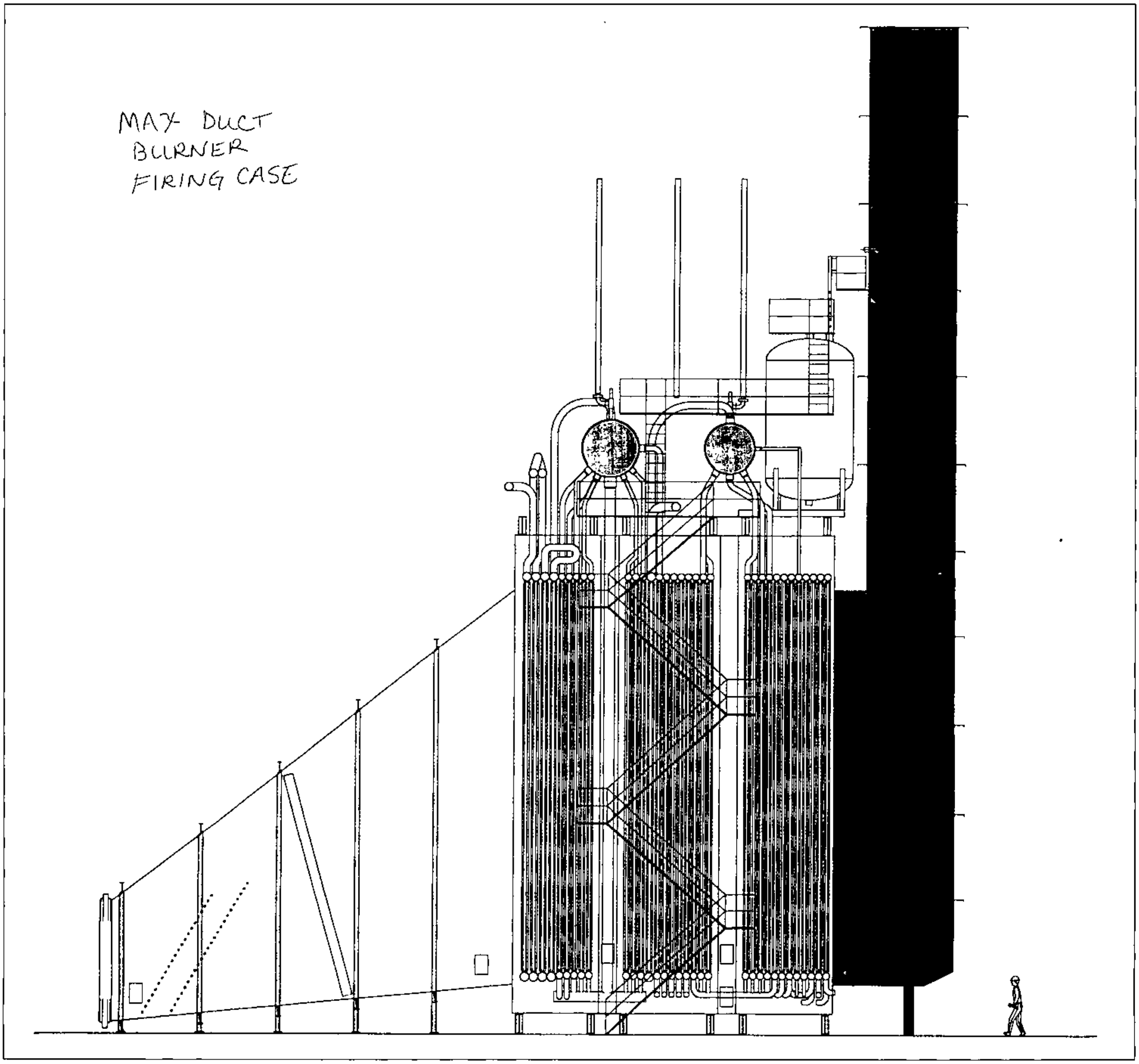
Air Products and Chemicals, Inc.
Orlando Cogen Project
Orlando, Florida

ABB
ASEA BROWN BOVERI

ABB Combustion Engineering Systems
Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, CT 06095-0500

HRSG Steam Conditions

	Capacity lb/hr	Pressure psig	Temperature degrees F
HP	**368,200**	**1140**	**930**
LP	**66,500**	**100**	**563**



CAMBRIA COGEN
03-1-8011

MATERIAL BALANCE
REFER TO PROCESS FLOW DIAGRAM 03-1-8011-55.10

J.T.KINDT
25 FEB 92

STREAM NUMBER	LOCATION	FLUID	UNFIRED PSIA	UNFIRED degF	UNFIRED LB/HR	SUPP FIRED PSIA	SUPP FIRED degF	SUPP FIRED LB/HR	
100	INLET AIR FILTER	AIR	14.7	72	ABB-PGI	14.7	72	ABB-PGI	
105	INLET OF FUEL PREHEATER	NATURAL GAS	414.7	60	39,476	414.7	60	44,741	@ 20,896 BTU/LB LHV
110	FUEL TO DUCT BURNER	NATURAL GAS	414.7	60	0	414.7	60	5,264	@ 20,896 BTU/LB LHV
115	FUEL TO COMBUSTOR	NATURAL GAS	404.7	293	39,476	404.7	293	39,476	@ 20,896 BTU/LB LHV
120	GT EXHAUST	FLUE GAS	15.1	965	2,420,000	15.1	965	2,420,000	12"WC HRSG dP
122	DUCT BURNER OUTLET	FLUE GAS	ABB-CE	965	2,420,000	ABB-CE	1117	2,425,241	
125	HRSG STACK	FLUE GAS	14.7	220	2,420,000	14.7	220	2,425,241	
200	HP SUPERHEATER OUTLET	HP STEAM	1152.8	930	274,000	1301.2	932	368,200	ABB-CE GUARANTEE
202	HP TURBINE INLET	HP STEAM	1106.6	924.4	270,870	1225.5	925.5	368,200	ABB-PGI REQUIREMENT
204	HP TURBINE INLET	HP STEAM	1106.6	924.4	274,000	1225.5	925.5	368,200	USED IN MAT'L BAL
204	TO GLAND STEAM SYSTEM	HP STEAM	1106.6	924.4	0	1225.5	925.5	0	
206	LP SUPERHEATER OUTLET	LP STEAM	95	536	79,100	115.2	563	66,500	ABB-CE GUARANTEE
208	LP TURBINE INLET	LP STEAM	87.4	532.4	78,840	112.1	568.8	63,200	ABB-PGI REQUIREMENT
210	LP TURBINE INLET	LP STEAM	87.4	532.4	79,100	112.1	568.8	66,500	USED IN MAT'L BAL
210	PEGGING STEAM TO DA	LP STEAM	103.7	330	0	122.7	343	0	
212	LP TURBINE PROCESS EXTR.	LP STEAM	35	324	32,600	35	324	32,600	
214	ABSORP SYS. CONCENTRATOR INLET	LP STEAM	26.7	243	32,600	26.7	243	32,600	TRANE GUARANTEE
216	LP TURBINE EXTR. TO DA	LP STEAM			4,950			7,100	ABB TO CONFIRM P/T
218	EXTR. STEAM AT DA	LP STEAM	2.9	140	4,950	2.9	140	7,100	
220	STEAM TO DA	LP STEAM	2.9	140	4,950	2.9	140	7,100	
222	HP TURBINE BYPASS	HP STEAM	1106.6	924.4	0	1225.5	925.5	0	
224	EXIT OF BYPASS VALVE	LP STEAM	1.37		0	1.37		0	
226	LP TURBINE EXHAUST	LP STEAM	1.37	113	314,830	1.37	113	394,070	
228	INLET OF MAIN CONDENSER	LP STEAM	1.37	113	314,830	1.37	113	394,070	
230	DEAERATOR VENT	NON CONDENS	2.9	140	0.2	2.9	140	0.2	
232	CONDENSER VENT	NON CONDENS	1.37	113	22.5	1.37	113	22.5	
234	INLET OF VACUUM PUMPS	NON CONDENS	1.37	113	22.7	1.37	113	22.7	
300	DEMIN MAKE-UP TO COND. STORAGE	DEMIN WATER			25,000			25,000	50 GPM DEMIN CAPACITY
302	COND XFER PUMP DISCH	DEMIN WATER			3,819			4,641	1% OF MAKE:PUMP @ MIN
304	OUTLET OF MAIN CONDENSER	CONDENSATE	1.37	113	319,369	1.37	113	399,641	
306	CONDENSATE PUMP DISCH	CONDENSATE	75.6	113	319,369	76.3	113	399,641	
308	GLAND CNDNSR EXIT	CONDENSATE		113	319,369		113	399,641	DUTY IGNORED
310	MAIN CONDENSATE TO DA	CONDENSATE	2.9	113	319,369	2.9	113	399,641	
312	ABSORP SYS. CONDENSATE RETURN	CONDENSATE	14.7	212	32,600	14.7	212	32,600	
314	ABSORP SYS CONDENSATE AT DA	CONDENSATE	2.9	212	32,600	2.9	212	32,600	
316	HP FW TO FUEL PREHEATER	HP FEEDWATER	1236	324	28,807	1394	320 ~~324~~	29,443	
318	HP FW FROM FUEL PREHEATER	HP FEEDWATER	1226	130	28,807	1384	130	29,443	
320	FW FROM DA AT BFW PUMP INLET	FEEDWATER	23.7	140	385,726	23.7	140	468,784	
322	BFW PUMP LP FW DISCH	LP FEEDWATER	225.7	140	79,891	244.7	140	67,165	PUMP ENERGY NOT ADDED
324	BFW PUMP HP FW DISCH	HP FEEDWATER	1368.7	140	305,835	1548.7	140	401,619	PUMP ENERGY NOT ADDED
326	LP FW TO GLAND SYSTEM	LP FEEDWATER	225.7	140	?	244.7	140	?	ABB-PGI TO CONFIRM
328	HP FW TO BYPASS ATTEMPORATOR	HP FEEDWATER	1368.7	140	0	1548.7	140	0	
330	GLAND SEAL LEAKAGE	LP STEAM			720			930	ABB-PGI TO CONFIRM
332	GLAND CONDENSER DRAIN	CONDENSATE	1.37		720	1.37		930	

CAMBRIA COGEN
03-1-8011

MATERIAL BALANCE
REFER TO PROCESS FLOW DIAGRAM 03-1-8011-55.10

J.T.KINDT
25 FEB 92

STREAM NUMBER	LOCATION	FLUID	UNFIRED PSIA	UNFIRED degF	UNFIRED GPM	SUPP FIRED PSIA	SUPP FIRED degF	SUPP FIRED GPM	
400	CW CIRC PUMP DISCH	COOLING WATER		84	37.969		84	45.673	
402	INLET OF SIDESTREAM FILTERS	COOLING WATER		84	743		84	893	2% OF CIRC RATE
404	EXIT OF SIDESTREAM FILTERS	COOLING WATER		84	743		84	893	
406	SIDESTREAM FILTER BACKWASH	COOLING WATER		84	0		84	0	NOT CONTINUOUS
408	CW BLOWDOWN	COOLING WATER		84	93		84	112	0.251% OF CIRC RATE
410	MAIN CONDENSER INLET	COOLING WATER		84	29.067		84	36.434	
412	MAIN CONDENSER OUTLET	COOLING WATER		106	29.067		106	36.434	
414	CHILLER CW BOOSTER PUMP SUCTION	COOLING WATER		84	5.850		84	5.850	
416	CHILLER CW BOOSTER PUMP DISCH	COOLING WATER		84	5.850		84	5.850	
418	CHILLER CONDENSER EXIT	COOLING WATER		102	5.850		102	5.850	
420	BOP CW BOOSTER PUMP SUCTION	COOLING WATER		84	2.216		84	2.384	
422	BOP CW BOOSTER PUMP DISCH	COOLING WATER		84	2.216		84	2.384	
424	TO VAC PUMPS & ST OIL COOLER	COOLING WATER		84	399		84	479	~~[illegible]~~ GPM ?
426	VACUUM PUMP COOLER INLET	COOLING WATER		84	? 14	~~[illegible]~~ [illegible] 40	84	14	40
428	VACUUM PUMP COOLER OUTLET	COOLING WATER		106	14		106	14	
430	ST OIL COOLER INLET	COOLING WATER		84	385		84	465	
432	ST OIL COOLER OUTLET	COOLING WATER		106	385		106	465	
434	FROM VAC PUMPS & ST OIL COOLER	COOLING WATER		106	399		106	479	
436	TO GT & BFW OIL & GEN COOLERS	COOLING WATER		84	1817		84	1905	
438	GAS TURBINE OIL COOLER INLET	COOLING WATER		84	705		84	705	
440	GAS TURBINE OIL COOLER EXIT	COOLING WATER		106	705		106	705	
442	BFW PUMP OIL COOLERS INLET	COOLING WATER		84	22		84	28	
444	BFW PUMP OIL COOLERS OUTLET	COOLING WATER		106	22		106	28	
446	GENERATOR COOLERS INLET	COOLING WATER		84	1.090		84	1.172	
448	GENERATOR COOLERS OUTLET	COOLING WATER		106	1.090		106	1.172	
450	FROM GT & BFW OIL & GEN COOLERS	COOLING WATER		106	1.817		106	1.905	
452	BOP CW OUTLET	COOLING WATER		106	2.216		106	2.384	
454	RETURN TO COOLING TOWER	COOLING WATER		106	37.133		106	44.668	
456	COOLING TOWER EVAPORATION	COOLING WATER			654			786	1.76% OF RETURN
458	COOLING TOWER MAKE-UP	COOLING WATER		72	739		72	889	
460	BOILER BLOWDOWN	COOLING WATER			8			9	
470	ASU CW BOOSTER PUMP SUCTION	COOLING WATER		76	1.660		76	1.660	
472	ASU CW BOOSTER PUMP DISCH	COOLING WATER		76	1.660		76	1.660	
474	CHILLED ASU COOLING WATER	COOLING WATER		52	1.660		52	1.660	