Tropicana

Nancy R. Levenson
Staff Counsel

Tropicana Products, Inc.
P.O. Box 338
Bradenton, Florida 34206
813 747-4461

RECEIVED
MAY 1 1989
DER - BAQM

April 25, 1989

CERTIFIED - RETURN RECEIPT REQUESTED

Mr. C. E. Fancy, P.E., Deputy Chief
Bureau of Air Quality Management
Florida Dept. of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: DER File Nos. AC 41-157745
AC 41-150485
PSD-FL-136

Dear Mr. Fancy:

Enclosed please find the required proof of publication with regard to the issuance of the above-referenced permits.

This publication supersedes the March 25, 1989 publication which was erroneously published.

Sincerely,

Nancy R. Levenson

jlb

Enclosure

cc: J. Jost
G. Hartman
S. Woolwine
P. Raval

327-Der-cogen

copied: B. Andrews
[illegible]
T. Thomas, SW Dist.
[illegible], Manatee Co.
[illegible], EPA

File

The Bradenton Herald

102 MANATEE AVE. WEST, P.O. BOX 921
BRADENTON, FLORIDA 34206
TELEPHONE (813) 748-0411

PUBLISHED DAILY
BRADENTON, MANATEE COUNTY, FLORIDA

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MAY 1 1989

DER - BAQM

STATE OF FLORIDA
COUNTY OF MANATEE:

Before the undersigned authority personally appeared Tina Keenan, who on oath says that she is the Legal Advertising Clerk and the official representative of the Publisher of The Bradenton Herald, a daily newspaper published at Bradenton in Manatee County, Florida, with the express, limited authority to execute this affidavit for the purpose of establishing proof of publication of the public or legal notice and advertisement in the form attached hereto; that the attached copy of advertisement, being a legal advertisement in the matter of

State of Florida Department of Environmental Regulation - Notice of Intent To Issue
in the ______ Court,

was published in said newspaper in the issues of
4/19/89

Affiant further says that the said The Bradenton Herald is a newspaper published at Bradenton, in said Manatee County, Florida, and that the said newspaper has heretofore been continuously published in said Bradenton, Manatee County, Florida, each day and has been entered as second class mail matter at the post office in Bradenton, in said Manatee County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and the affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Tina Keenan

Sworn to and subscribed before me this
19th day of April
A.D. 1989
[signature]
(SEAL) Notary Public

Notary Public, State of Florida at Large
My Commission Expires May 30, 1991

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APR 21 1989

N. R. LEVENSON

**STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF INTENT
TO ISSUE**

The Department of Environmental Regulation hereby gives notice of its intent to issue permits to Tropicana Products, Inc., P.O. Box 338, Bradenton, Florida 33506, to construct a cogeneration project consisting of a gas turbine/heat recovery steam generator and an auxiliary boiler at the Tropicana facility in Bradenton, Manatee County, Florida.

A determination of Best Available Control Technology (BACT) was required. BACT is represented for control of nitrogen oxides. In determining BACT, the Department considered the impact of the control technology on air pollutants that may be emitted by the source including toxics and those not regulated by the Clean Air Act. A discussion of how BACT was determined is included in the Department's preliminary determination.

The maximum degree of increment consumed for nitrogen dioxide is 4.0% of the Class II proposed annual mean.

The maximum combined pollutant concentration from Tropicana and the other sources in the area will be less than the National Ambient Air Quality Standards (NAAQS). The NAAQS are levels set by the Environmental Protection Agency which identify the ambient concentration necessary to protect human health and welfare with an adequate margin of safety.

The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within fourteen (14) days of the publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by Petitioner, if any;

(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;

[illegible] statement of which

Tina Keenan

Sworn to and subscribed before me this

19th day of April

A.D. 1989

[signature]

(SEAL) Notary Public

Notary Public, State of Florida at Large
My Commission Expires May 30, 1991

RECEIVED

APR 21 1989

N. R. LEVENSON

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by Petitioner, if any;

(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement of which rules or statutes petitioner contends require reversal or modification to the Department's action or proposed action; and

(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of
Environmental Regulation
Bureau of Air
Quality Management
2600 Blair Stone Road
Tallahassee, Florida
32399-2400

Department of
Environmental Regulation
Southwest District Office
4520 Oak Fair Blvd.
Tampa, Florida 33610

Department of Health and
Rehabilitative Services
Manatee County Health Unit
202 Sixth Avenue, E.
Bradenton, Florida 33508

Any person may send written comments or request a public hearing on the proposed action to Mr. Bill Thomas at the Department's Tallahassee address. All comments mailed within 30 days of the publication of this notice will be considered in the Department's final determination. Furthermore, a public hearing can be requested by any person. Such requests must be submitted within 30 days of this notice.

4/19/89

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

4APT-APB-cdw
APR 20 1989

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APR 24 1989

DER-BAQM

Mr. C. H. Fancy, P.E., Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental
Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Tropicana Products Inc. (PSD-FL-136)

Dear Mr. Fancy:

This is to acknowledge receipt of your preliminary determination and draft prevention of significant deterioration (PSD) permit for the above referenced company, dated March 21, 1989. We have reviewed the package and have the following comments to offer, as discussed between Mr. Pradeep Raval of your staff and Gregg Worley of my staff on April 18, 1989.

NSPS

The proposed gas turbine (GT) will be subject to Standards of Performance for New Stationary Sources (NSPS) in accordance with 40 CFR 60 Subpart GG (see CFR 60.330 for applicability).

BACT Determination

Although the applicant correctly identified the top control option for the gas turbine and heat recovery steam generator (i.e., selective catalytic reduction with steam injection), the justification for dismissing SCR was not sufficient. The sole criteria used for rejecting SCR was the cost per ton for the removal of NO_x emissions after the employment of steam injection.

In reviewing the NSPS Subpart GG, it is obvious that steam (water) injection is considered a control technology. As stated in our comments of December 28, 1988, the applicant used a loading of 42 ppm of NO_x at 15% O_2, dry basis, to calculate the "uncontrolled" potential NO_x emissions. The 42 ppm would be reached by steam injection--a control technology. In evaluating the cost of the control system, the total uncontrolled emissions should be the basis with the total controlled emissions used to calculate the cost effectiveness, i.e.,

$$\frac{\text{ANNUALIZED COST OF SCR + STEAM INJECTION}}{\text{TONS OF } NO_x \text{ REMOVED BY SCR + STEAM INJECTION}}$$

Likewise, the next best level of control would evaluate the use of SCR without steam injection based on uncontrolled emissions, and so on.

In any event, the use of $1000 per ton of NO_x removed as a screening value in making control technology determinations is not acceptable. In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant. Obviously, SCR on gas turbines is a demonstrated technology. Numerous applications of this control have been made in the United States for units in the same size range (40-50 MW) as the proposed Tropicana project. Recently, a GE 60 MW gas turbine was permitted in Rhode Island with a heat recovery steam generator (HRSG) and an auxiliary boiler with a capacity of 65 mmBTU/hr. The turbine was permitted at a limit of 9 ppmv, @ 15% O_2, dry basis, for NO_x when firing natural gas. What makes Tropicana's proposed project so fundamentally different that the same type of controls would be economically infeasible?

Public Notice

The copy of the public notice published in the Bradenton Herald on March 25, 1989, apparently did not reference a 30 day comment period, the BACT determination or the opportunity to review the material related to the preliminary determination. If this was the only public notice published, we would request that a new public notice be issued containing the above omitted information.

Thank you for the opportunity to comment on this package. If you have any questions on these comments, please feel free to contact me or Gregg Worley of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
Management Division

cc: Griscom Bettle, III, Vice President
Tropicana Products, Incorporated
P.O. Box 338
Bradenton, Florida 33506

Barry Andrews, FL DER
Pradeep Raval, FL DER

04/20/89 08:53 EPA OF ATL NO.999 P001

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APR 20 1989

DER - BAQM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, REGION IV
345 Courtland Street, N.E.
ATLANTA, GA 30308

FACSIMILE TRANSMISSION SHEET

DATE: 4/20/89 NUMBER OF PAGES: 3 (Included Cover Sheet)

TO: MR. PRADEEP RAVAL PHONE: (904) 488-1349

ADDRESS: BUREAU OF AIR QUALITY MGT. FAX NUMBER: (904) 488-6579

FROM: GREGG WORLEY EPA PHONE: (404) 347-2864

If the following message is received poorly, Please call G. WORLEY in our office at FTS 257-2864 or commercial (404) 347-2864

SPECIAL INSTRUCTIONS:

ORIGINAL SENT IN REGULAR MAIL

PLEASE NUMBER ALL PAGES

Patty,
I've copied the folks below.

REGIONAL OFFICE FAX NUMBER:

[illegible]	TELEPHONE NUMBERS
3M, EMT 9165	FTS 257-4486 (AUTO) COMM. (404) 347-4486
[illegible]	FTS 257-4702

Copied [illegible]

NOX CONTROL IN REGION 9
(Historically Speaking...)

1978 Lo-NOx burners required for oil-fired steam injection boilers (enhanced oil recovery) in Kern County, California. [BACT]

1980 A municipal waste-fired resource recovery facility was proposed for the San Francisco Bay Area which included Thermal-DeNOx for control of NOx emissions. [BACT]

1982 The South Coast AQMD required a Thermal-DeNOx retrofit on a wood waste-fired boiler. [LAER]

1983 Region 9 required water injection for control of NOx emissions from a gas turbine cogeneration facility. [BACT]

1984 The South Coast AQMD required Thermal-DeNOx on the Commerce Resource Recovery Facility. Commerce has been constructed and is currently in operation. [LAER]

1984 Region 9 recommended and the South Coast AQMD determined that Selective Catalytic Reduction (SCR) and water injection is LAER for gas-fired turbine cogeneration projects. The South Coast adopted a limit of 9 ppm for NOx. Other California districts adopted limits of 15-25 ppm for NOx on gas turbines.

1985 The South Coast AQMD required Thermal-DeNOx on the municipal waste-fired Southeast Resource Recovery Facility located in Long Beach, California. SERRF has been constructed and is currently undergoing source testing. [LAER]

1985 Region 9 required Thermal-DeNOx on six coal-fired fluidized bed power plants. [BACT]

1986 Region 9 required Thermal-DeNOx on the Stanislaus Waste to Energy Facility. [BACT]

1986 South Coast AQMD proposed SCR in conjunction with Thermal-DeNOx for control of NOx emissions from the Los Angeles City Resource Recovery Facility, the SPADRA resource recovery project, and from the Milliken Landfill facility. [LAER]

ROUTING AND TRANSMITTAL SLIP

Date 4/18/89

TO: (Name, office symbol, room number, building, Agency/Post)	Initials	Date
1.		
2. Pradeep Raval		
3.		
4.		
5.		

Action	File	Note and Return
Approval	For Clearance	Per Conversation
As Requested	For Correction	Prepare Reply
Circulate	For Your Information	See Me
Comment	Investigate	Signature
Coordination	Justify	

REMARKS

Pradeep,

Here is the information on Region 9 and the Rhode Island permits for gas turbines.

Gregg

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APR 19 1989

DER - BAQM

DO NOT use this form as a RECORD of approvals, concurrences, disposals, clearances, and similar actions

FROM: (Name, org. symbol, Agency/Post)	Room No.—Bldg.
GREGG WORLEY EPA REGION IV	Phone No. (404) 347-2864

5041-102

OPTIONAL FORM 41 (Rev. 7-76)
Prescribed by GSA
FPMR (41 CFR) 101-11.206

1986 Region 9 required Thermal-DeNOx on a flat glass manufacturing facility. [BACT]

1986 Region 9 required an SCR system with a NOx emission limit of 25 ppm on a gas turbine cogeneration facility. [BACT]

1987 Two California districts required Thermal-DeNOx on resource recovery facilities proposing to fire used tires. The Modesto Energy Facility has been constructed and is currently in operation (exempt from EPA PSD).

1988 Region 9 set a 10 ppm NOx emission limit with an SCR system on a gas turbine cogeneration facility. [BACT]

1988 Region 9 required Thermal DeNOx for control of NOx emissions on two wood waste-fired projects and on one agricultural waste-fired facility. [BACT]

<u>Summary</u>

Currently it is Region 9's policy to require all municipal waste-fired and tire-fired resource recovery facilities and all wood waste, agricultural waste, and bio-mass fired facilities to incorporate Thermal-DeNOx as a NOx control strategy. Region 9 is aware of 35 such projects located within the Region (see Attachment).

There are 17 coal-fired boilers currently located or permitted in Region 9 incorporating Thermal-DeNOx as a NOx control strategy (see Attachment).

Currently most Region 9 districts require NOx limits of <10 ppm for NOx on gas-fired and some oil-fired turbine cogeneration projects. Approximately 35 gas turbine projects are located or are proposing to locate in Region 9 (see Attachment). Also, please note that these numbers are based on 1987 data and do not include projects proposed in 1988.

SOLID FUELS COMBUSTION PROJECTS USING AMMONIA INJECTION SYSTEM

I. COAL-FIRED*

PROJECT NAME (LOCATION) & EPA PERMIT FILE NUMBER	PERMITTING AGENCY	NO_x EMISSION LIMITS** (ppm)	CONTROL EFFICIENCY (%)	PROJECT STATUS
1. (SJ 85-04) Corn Products (Stockton)	EPA	50	n/a	Operating (S.T. 6/88)
2. (SJ 84-05) Cogen. National Co. (Stockton)	EPA	30	80-90	Operating (not S.T. ye
3. (SJ 86-08) GWF Power Systems (Kings County)	EPA	28	85	Permitted 1/8
4-8. GWF Power Systems (5 in Bay Area)	BAAQMD	30	85	Permit pendin
9-10. GWF Power Systems (2 in Fresno)	Fresno Co.	0.037 lbs/MMBtu (eq. to 28 ppm)	n/a	Permit pendin
11. (SJ 85-06) Rio Bravo (Poso Creek, Kern)	EPA	78	n/a	Construction
12. (SJ 85-07) Rio Bravo (Jasmin O.F., Kern)	EPA	78	n/a	Construction
13. (SJ 85-09) Mt. Poso Cogen. Company (Kern)	EPA	65	n/a	Permitted 1/8
14. (SE 85-01) SCE-Biogen (Ivanpah Valley)	EPA	34	n/a	Operating (not S.T. ye
15. (SE 86-04)*** Kerr McGee (Trona, CA)	San Bernardino Co.	0.09 lbs/MMBtu	96.4	Construction
16. Thomas Oil Co. (Kern)	Kern Co.	0.038 lbs/MMBtu	n/a	Permit pendin
17. Sunlaw Cogen. (Monterey)	Monterey Co.			Permit pendin
18. GWF Power Systems (Torrance, Kern Co.)	Kern Co.	22 (achieved 8.7 ppm)		Operating (Permitted 10/
19. AES (Campbell)	Hawaii DOH			Proposed
20.				
21.				
22.				
23.				

* Circulating Fluidized Bed Combustion Design
** Emission limits are in parts per million (ppm) @ 3% O_2, unless otherwise indicated.
*** EPA PSD permit applies to carbon monoxide (CO) emissions only.
S.T.: source tested for compliance

SOLID FUELS COMBUSTION PROJECTS USING AMMONIA INJECTION SYSTEM (cont'd)

II. MUNICIPAL SOLID WASTE-FIRED

	PROJECT NAME (LOCATION)	PERMITTING AGENCY	NO_x EMISSION LIMITS** (ppm)	CONTROL EFFICIENCY (%)	PROJECT STATUS
1.	(LA 83-01) SERRF (Long Beach, CA)	EPA	115	30	Operating (S.T. 11/88)
2.	Commerce (Los Angeles)	South Coast	162	15	Operating (S.T. 1986)
3.	(SJ 86-03) Stanislaus Waste Energy	EPA	165	40	Operating (S.T. 12/88)
4.	(LA 85-01) Irwindale	EPA		40	Proposed/ Cancelled
5.	(LA 87-01) Ogden Martin System**** (San Bernardino)	EPA	37		Permitted/ Cancelled
6.	Los Angeles City Energy Recovery (Lancer)	-	0.45 lbs/MMBtu (<225 ppm @ 3% O_2)	38-43.5	Proposed/ Cancelled
7.	(SD 85-01) North County RRA (San Diego)	EPA			Proposed
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* Circulating Fluidized Bed Combustion Design
** Emission limits are in parts per million (ppm) @ 12% CO_2, unless otherwise indicated.
*** LAER limits apply in non-attainment areas.
**** Also incorporated selective catalytic reduction (SCR)
S.T.: source testing for compliance

SOLID FUELS COMBUSTION PROJECTS USING AMMONIA INJECTION SYSTEM (cont'd)

III. WOOD-FIRED (woodwaste/biomass/ag. waste)

	PROJECT NAME (LOCATION)	PERMITTING AGENCY	NO_x EMISSION LIMITS** (lb/MMBtu)	CONTROL EFFICIENCY (% reduction)	PROJECT STATUS
1.	Proctor & Gamble (Long Beach)	SCAQMD	0.265 (achieved 0.222 lbs/MMBtu)	32-40	Operating (S.T. 12/8
2.	Ultrapower* (Chinese Station)	Tuolumne Co.	0.147	n/a	Operating (S.T. 10/8
3.	Dinuba Enerby/Yanke Energy	Tulare Co.	0.12***	68	Operating (S.T. 5/87
4.	Sierra Forest Products	Tulare Co.	0.108***	n/a	Operating (S.T. 9/87
5.	ABS Energy (Madera)	Madera Co.	0.061	n/a	Permitted
6.	Wheelabrator Delano Power Plant (AKA. Valley Power)	Kern Co.	0.08***	n/a	Permitted
7-8.	Chowchilla Biomass (2 plants)	Madera Co.	0.25	50	Permitted
9.	Mendota Biomass Power, Ltd.*	Fresno Co.	13.9 lbs/hr (= 0.072 lbs/MMBtu)	55	Permitted
10.	Ultrapower (Malaga)	Fresno Co.			Construction
11.	(NE 87-01) Honey Lake Power (Lassen Co.)	EPA	0.10		Construction
12.	(SE 87-01) Colmac Energy Inc.* (Cabazon)	EPA	0.10 (= 25 ppm)		Permitted 6/8
13.	Capco Madera, Inc. (Madera)	Madera Co.	0.15	70	Permitted 8/8
14.	North Fork/Yanke Energy	Madera Co.	0.147		Permit pendin
15.	Auberry Energy* (Auberry)	Fresno Co.	0.117		Operating (S.T. 9/87)
16.	Western Forest Products* (Soledad)	Monterey	1.18 lbs/MW-hr	53	Permitted 7/8
17.	Soledad Energy* (Soledad)	Monterey			Permitted
18.	Thermal Energy Devt. Co. (Tracy)	San Joaquin	0.105	75	Permitted
19.	Industrial Power Tech.*(Soledad)	Monterey	0.74 lbs/MW-hr (= 0.063 lbs/MMBtu)	70	Permitted 9/8

* Circulating Fluidized Bed Combustor
** Emission limits are in pounds per million Btu's (lbs/MMBtu), unless otherwise indicated.
*** LAER limits apply in non-attainment areas.
S.T.: source testing for compliance.

SOLID FUELS COMBUSTION PROJECTS USING AMMONIA INJECTION SYSTEM (cont'd)

III. WOOD-FIRED (cont'd)

	PROJECT NAME (LOCATION)	PERMITTING AGENCY	NO_x EMISSION LIMITS** (lb/MMBtu)	CONTROL EFFICIENCY (% reduction)	PROJECT STATUS
20.	Woodland Biomass Power, Ltd.	Yolo-Solano	0.08	n/a	Permit pending
21.	Five Points Biomass Power Plant Assoc.*	Fresno Co.	0.25		Permitted 3/88
22.	Sanger Bio Mass Energy Company	Fresno Co.	0.08	n/a	Permitted 6/88
23.	Wheelabrator Signal Energy (Anderson)	Shasta Co.	0.12	40	Operating (not S.T. yet)
24.	Burney Forest Products (Shasta)	Shasta Co.	0.12	40	Permitted 5/88
25.	(SAC 87-01) Sierra Pacific Industries (Loyalton, CA)	EPA	0.110	50	Permitted 6/88
26.	Western Power Group II	Imperial Co.	0.24		Permitted
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* Circulating Fluidized Bed Combustion Design

** Emission limits are in pounds per million Btu's (lbs/MMBtu), unless otherwise indicated.

*** LAER limits apply in non-attainment areas.

S.T.: source testing for compliance

SOLID FUELS COMBUSTION PROJECTS USING AMMONIA INJECTION SYSTEM

IV. OTHER SOLID FUELS (ie. tire, manure...)

	PROJECT NAME (LOCATION)	PERMITTING AGENCY	NO_x EMISSION LIMITS** (ppm)	CONTROL EFFICIENCY (%)	PROJECT STATUS
1.	Modesto Energy -- tire burning	Stanislaus Co.	0.075 lbs/MMBtu	55	Operating
2.	Rialto Power* -- tire burning	South Coast			Proposed
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* Circulating Fluidized Bed Combustion Design
** Emission limits are in parts per million (ppm) @ 12% CO_2, unless otherwise indicated.
*** LAER limits apply in non-attainment areas.

EPA Region IX
New Source Section
1/11/89 (TWA)

SOURCE TEST RESULTS
SOLID FUELS COMBUSTION PROJECTS USING AMMONIA INJECTION SYSTEM

PROJECT NAME (LOCATION) & EPA PERMIT FILE NUMBER	PERMITTED NO_x EMISSION LIMIT**	ACTUAL NO_x EMISSION RATE FROM SOURCE TEST	AMMONIA SLIP	DATE OF SOURCE TEST
I. COAL-FIRED	(ppm)	(ppm)	(ppm)	
1. (SJ 85-04) Corn Products* (Stockton)	50	23.4	22.12	06/08/88
2. GWF Power Systems (Torrance, Kern Co.)	22	8.7		
II. MUNICIPAL SOLID WASTE-FIRED	(ppm)	(ppm)	(ppm)	
1. (LA 83-01) SERRF (Long Beach, CA)	115	71.5	17.0	11/14/88
2. Commerce (Los Angeles)	162	110	10.2	06/02/88
3. (SJ 86-03) Stanislaus Waste Energy	165	(TEST RESULTS NOT YET AVAILABLE)		12/20/88
III. WOOD-FIRED (woodwaste/biomass/ag. waste)	(lb/MMBtu)	(lb/MMBtu)	(ppm)	
1. Proctor & Gamble (Long Beach)	0.265	0.222	3.2	12/23/86
2. Ultrapower* (Chinese Station)	0.147	0.145	5.0	10/01/86
3. Dinuba Enerby/Yanke Energy	0.12	0.071		05/22/87
4. Sierra Forest Products	0.108	0.093		09/21/87
5. Auberry Energy* (Auberry)	0.117	0.086		09/03/87

* Circulating Fluidized Bed Combustor

** Emission limits are in parts per million (ppmv) @ 3% O_2, unless otherwise indicated.

Gas Turbines Abated by SCR in California

-1987-

Company	Location	MW	Control Level	Status
AES Placerita	Newhall	83.2	7 ppmv @ 15% O_2	Permit
American Cogeneration Technology	Spreckles	57.6	17 ppmv @ 15% O_2	Permit
ARCO	Carson	385	90% Reduction	Application
Basic American Foods	King City	120	15 ppmv @ 15% O_2	Application
Chevron	El Segundo	77	90% Reduction	Application
Chevron	Gaviota	17.5	19 ppmv @ 15% O_2	Permit
Chevron	Richmond	99	10 ppmv @ 15% O_2	Application
Cogeneration Company	Wilmington	3.3	9 ppmv @ 15% O_2	Permit
Corona Cogeneration, Inc.	Corona	48	6 ppmv @ 15% O_2	Permit
Double C Limited	Kern Co.	49.9	4.5 ppmv @ 15% O_2	Permit
Energy Reserve	Kern Co.	20.5	92.5% Reduction	Permit
Griswold Controls	Corona	49.7	9 ppmv @ 15% O_2	Permit
Kern Bluff LTD	Kern Co.	48.6	5 ppmv @ 15% O_2	Permit
Kern Energy Corp.	Kern Co.	42	87% Reduction	Permit
Kern Front LTD	Kern Co.	49.9	4.5 ppmv @ 15% O_2	Permit

Company	Location	MW	Control Level	Status
Klondike Equality Enterprises	Santa Ana	22	9 ppmv @ 15% O_2	Permit
Martinez Cogeneration	Martinez	50	25 ppmv @ 15% O_2	Permit
Monarch Cogeneration	Kern Co.	16.8	92% Reduction	Operate
Moran Power	Kern Co.	42	87% Reduction	Permit
O'Brien Energy Systems	Artesia	22.2	9 ppmv @ 15% O_2	Permit
O'Brien Energy Systems	Corona	26.7	9 ppmv @ 15% O_2	Permit
O'Brien Energy Systems	Modesto	40.9	5 ppmv @ 15% O_2	Permit
O'Brien Energy Systems	Salinas	40.4	15 ppmv @ 15% O_2	Permit
OLS	Camarillo	24.7	9 ppmv @ 15% O_2	Permit
Proctor and Gamble	Oxnard	40.4	9 ppmv @ 15% O_2	Permit
San Joaquin Cogeneration LTD	Lathrop	48.6	6 ppmv @ 15% O_2	Permit
Santa Fe Energy	Brea	11.6	9 ppmv @ 15% O_2	Permit
Sierra Ltd Cogeneration	Kern Co.	49.9	4.5 ppmv @ 15% O_2	Permit
Southeast Energy	Kern Co.	42	87% Reduction	Permit
Tenneco	Newhall	22	9 ppmv @ 15% O_2	Permit

Company	Location	MW	Control Level	Status
Union Oil	Rodeo	49.8	25 ppmv @ 15% O_2	Permit
United Air Lines	San Francisco	21.8	16 ppmv @ 15% O_2	Operate
University Energy	Kern Co.	38.7	97% Reduction	Operate
Western Power System	Kern Co.	22	9 ppmv @ 15% O_2	Permit
Willamette Industries	Oxnard	21	15 ppmv @ 15% O_2	Operate

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

DIVISION OF AIR AND HAZARDOUS MATERIALS
291 Promenade Street
Providence, R. I. 02908-5767

1 February 1989

Mr. James S. Gordon
Energy Management, Inc.
8 Newbury Street
Boston, MA 02116

Dear Mr. Gordon:

Your applications for the construction and installation of a combined cycle cogeneration facility in Pawtucket have been reviewed and conditionally approved (Approval Nos. 948, 949, and 950). As approved, the facility is to be a gas turbine based facility utilizing the General Electric Frame 6 (Model PG6531B) combustion turbine with supplementary firing in the heat recovery steam generator. Additionally, the facility will have a 65 million BTU/hr auxiliary boiler.

This is a conditional approval because vendor specific design information and engineering drawings for the auxiliary boiler and selective catalytic reduction (SCR) system are not available at this time. Such information shall be provided to the Division at least 120 days prior to the anticipated date of construction/ installation of the specific piece of equipment. A final approval will be issued on the basis of review of that information.

Construction and operation of the Pawtucket Power Associates facility is subject to the attached permit conditions and emission limitations. Furthermore, these approvals do not relieve Pawtucket Power Associates from compliance with applicable air pollution control rules and regulations.

At least 180 days prior to start-up of the facility, Pawtucket Power Associates shall submit to the Division, for review and approval, its plan for monitoring the various plant operations required by Condition F.9 of this permit.

These approvals will remain in effect as long as the operation of this facility is satisfactory to the Director of the Department of Environmental Management.

Very truly yours,

Douglas L. McVay

Douglas L. McVay, Principal Engineer
Division of Air and Hazardous Materials

DLM:CAM
cc: Todd Olbrych, Pawtucket Building Official
George Lipka, HMM

enrgym.dm/CM

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
DIVISION OF AIR AND HAZARDOUS MATERIALS

Permit Conditions and Emissions Limitations
PAWTUCKET POWER ASSOCIATES

A. Emission Limitations - Turbine

1. Natural Gas Firing

a. Nitrogen Oxides (as nitrogen dioxide (NO_2)

1. The concentration of nitrogen oxides in the turbine exhaust flue shall not exceed 9 ppmv, on a dry basis, corrected to 15 percent O2 (1 hour average).

2. The emission rate of nitrogen oxides from the turbine exhaust flue shall not exceed 17.4 lbs/hr.

b. Carbon Monoxide (CO)

1. The concentration of carbon monoxide in the turbine exhaust flue shall not exceed 23 ppmv, on a dry basis corrected to 15 percent O2 (1 hour average).

2. The emission rate of carbon monoxide from the turbine exhaust flue shall not exceed 24.0 lbs./hr.

c. Sulfur Dioxide (SO_2)

The emission rate of sulfur dioxide from the turbine exhaust flue shall not exceed 0.006 lbs per million BTU heat input (HHV) or a maximum of 3.2 lbs./hr, whichever is more stringent.

d. Particulate Matter

The emission rate of particulate matter from the turbine exhaust flue shall not exceed 0.007 lbs per million BTU heat input (HHV) or a maximum of 2.5 lbs/hr, whichever is more stringent.

e. Total Nonmethane Hydrocarbons (NMHC)

1. The concentration of total nonmethane hydrocarbons in the turbine exhaust flue shall not exceed 19 ppmv, on a dry basis corrected to 15 percent O2 (1-hour average).

2. The emission rate of total nonmethane hydrocarbons from the turbine exhaust flue shall not exceed 11.4 lbs/hr.

f. Ammonia (NH_3)

1. The concentration of ammonia in the turbine exhaust flue shall not exceed 30 ppmv, on a dry basis, corrected to 15 percent O2 (1 hour average).

2. The emission rate of ammonia from the turbine exhaust flue shall not exceed 22.3 lbs/hr.

2. Oil Firing

a. Nitrogen Oxides (as nitrogen dioxide (NO_2)

1. The concentration of nitrogen oxides in the turbine exhaust flue shall not exceed 18 ppmv, on a dry basis, corrected to 15 percent O2 (1 hour average).

2. The emission rate of nitrogen oxides from the turbine exhaust flue shall not exceed 36.5 lbs/hr.

b. Carbon Monoxide CO

1. The concentration of carbon monoxide in the turbine exhaust flue shall not exceed 10 ppmv, on a dry basis, corrected to 15 percent O2 (1 hour average).

2. The emission rate of carbon monoxide from the turbine exhaust flue shall not exceed 11.0 lbs/hr.

c. Sulfur Dioxide (SO_2)

1. All fuel oil burned in the turbine shall contain 0.2 percent sulfur or less by weight.

2. The emission rate of sulfur dioxide from the turbine exhaust flue shall not exceed 105.4 lbs./hr.

d. Particulate Matter

The emission rate of particulate matter from the turbine exhaust flue shall not exceed 0.045 lbs. per million BTU heat input (HHV) or a maximum of 17.0, lbs/hr whichever is more stringent.

e. Total Nonmethane Hydrocarbons (NMHC)

1. The concentration of total nonmethane hydrocarbons in the turbine exhaust flue shall not exceed 8 ppmv, on a dry basis corrected to 15 pecent O2 (1 hour average).

2. The emission rate of total nonmethane hydrocarbons from the turbine exhaust flue shall not exceed 5.0 lbs/hr.

B. Emission Limitations - Auxiliary Boiler

1. Natural Gas Firing

a. Nitrogen Oxides (as NO2)

The emission rate of nitrogen oxides from the auxiliary boiler exhaust flue shall not exceed 0.2 lbs per million BTU heat input (HHV) or a maximum of 13 lbs/hr, whichever is more stringent.

b. Carbon Monoxide (CO)

The emission rate of carbon monoxide from the auxiliary boiler exhaust flue shall not exceed 0.17 lbs per million BTU heat input (HHV) or a maximum of 11 lbs/hr, whichever is more stringent.

c. Total Nonmethane Hydrocarbons (NMHC)

The emission rate of total nonmethane hydocarbons from the auxiliary boiler exhaust flue shall not exceed 0.02 lbs per million BTU heat input (HHV) or a maximum of 1.3 lbs/hr, whichever is more stringent.

2. Oil Firing

a. Nitrogen Oxides (as NO2)

The emission rate of nitrogen oxides from the auxiliary boiler exhaust flue shall not exceed 0.3 lbs per million BTU heat input (HHV) or a maximum of 18 lbs/hr, whichever is more stringent.

b. Sulfur Dioxide (SO2)

All fuel oil burned in the auxiliary boiler shall contain 0.2 percent sulfur or less by weight.

c. Particulate Matter

The emission rate of particulate matter from the auxiliary boiler exhaust flue shall not exceed 0.1 lbs per million BTU heat input (HHV) or a maximum of 6 lbs/hr, whichever is more stringent.

d. Carbon Monoxide (CO)

The emission rate of carbon monoxide from the auxiliary boiler exhaust flue shall not exceed 0.17 lbs per million BTU heat input (HHV) or a maximum of 11 lbs/hr, which is more stringent.

e. Total Nonmethane Hydrocarbons (NMHC)

The emission rate of total nonmethane hydrocarbons from the auxiliary boiler exhaust flue shall not exceed 0.02 lbs per million BTU heat input (HHV) or a maximum of 1.3 lbs/hr, whichever is more stringent.

C. Operating Requirements

1. In no event shall the hours of operation for the facility on oil exceed 1,000 hours in any 12 month period. An hour of operation on oil is defined as an hour during which oil is used as a fuel in either the combustion turbine or auxiliary boiler.

2. The duct burner shall be fired with natural gas only.

3. During periods when the combustion turbine is operating in a baseload condition, the auxiliary boiler shall be operating at no more than 33 million BTU per hour heat input (gas firing) and 30 million BTU per hour heat input (oil firing). During combustion turbine start-up periods, defined as when the turbine is in a full speed/no load condition, the auxiliary boiler may operate at maximum capacity--65 million BTU per hour heat input (gas firing) and 60 million BTU per hour heat input (oil firing).

4. In no event shall the hours of start-up operation for the combustion turbine exced 400 hours in any 12 month period.

5. The combustion turbine or auxiliary boiler shall be operated on gas only during periods when the Colfax Plant steam boiler is operating unless interactive modeling of Colfax and Pawtucket Power shows to the satisfaction of the Division that oil firing would not result in a violation of applicable standards and increments.

6. Visible emissions from any stack at this facility shall not exceed 10% opacity except for a period or periods aggregating no more than three minutes in any one hour.

D. Continuous Monitors

1. Continuous emission monitoring equipment shall be installed, operated and maintained for opacity, nitrogen oxides, carbon monoxide and oxygen.

2. The continuous monitors must satisfy EPA performance specifications in 40 CFR 60, Appendix B.

3. Performance specifications, monitor location, calibration and operating procedures, and quality assurance procedures for each monitor must be submitted to the

Division for review and approval at least 180 days prior to expected start-up.

4. All data shall be monitored and recorded continuously.

5. Natural gas and fuel oil flows to the turbine, the duct burner and auxiliary boiler shall be continuously measured and recorded.

6. A method for monitoring and recording ammonia concentrations in the turbine flue gases shall be proposed for the Division's approval and implementation.

7. Catalyst bed temperature shall be continuously measured and recorded.

8. Continuous emission monitoring equipment for opacity shall be installed, operated and maintained on the auxiliary boiler.

9. The facility shall have the capability of transmitting all of the collected continuous monitoring data to the Division's office via a telemetry system. The owner/operator must provide all of the necessary funds for installation and operation of this equipment. A plan for accomplishing this must be submitted to the Division for review and approval prior to installation of the equipment and at least 180 days prior to expected start-up. This plan shall also define procedures to test and protect the integrity of transmitted data.

E. Stack Testing

1. Within 180 days of start-up, initial performance testing shall be conducted for the turbine. Performance testing shall be conducted for nitrogen oxides, carbon monoxide, particulate matter (total and PM-10), sulfur dioxide, nonmethane hydrocarbons and ammonia.

2. A stack testing protocol shall be submitted to the Division for review and approval prior to the performance of any stack tests. The owner/operator shall provide the Division at least 60 days prior notice of any performance test.

3. All test procedures used for stack testing shall be approved by the Division prior to the performance of any stack tests.

4. The owner/operator shall install any and all test ports or platforms necessary to conduct the required stack testing, provide safe access to any platforms and pro-

vide the necessary utilities for sampling and testing equipment.

5. Initial performance testing shall be conducted when burning natural gas and when burning fuel oil. All testing shall be conducted under operating conditions deemed acceptable and representive for the purpose of assessing compliance with the applicable emission limitations.

6. A final report of the results of stack testing shall be submitted to the Division no later than 45 days following completion of the testing.

7. All stack testing must be observed by the Division or its authorized representatives to be considered acceptable.

F. Recordkeeping and Reporting

1. The owner/operator shall maintain a record of all measurements, performance evaluation, calibration checks, and maintenance or adjustments for each continuous monitor.

2. The owner/operator must notify the Division no later than one hour after a violation of any emission limitation is discovered. Notification shall include:
   - Identification of the emission standard violated
   - Suspected reason for the violation
   - Corrective action taken or to be taken
   - Anticipated length of violation

3. The owner/operator must provide a written report within 5 days of any violation of an emission standard. This report shall, at a minimum provide the information required in G.2.

4. The owner/oprator must notify the Division no later than one hour after the discovery that a continuous emission monitor has malfunctioned. Notification shall include:
   - The type and location of the malfunctioning monitor
   - The corrective action taken or to be taken
   - The anticipated time needed to repair or replace the monitor.

5. The owner/operator shall notify the Division of any anticipated noncompliance with the terms of this permit or any other applicable air pollution control rules or regulations.

6. The owner/operator shall maintain the following records for the turbine:
   - The hours of operation, including the hours for any start-up, shut-down event or malfunction in the operations of the facility.
   - The date, start time, end time and amount of fuel used for any period when fuel oil is burned.
   - Any malfunction of the air pollution control system.

7. The owner/operator shall maintain the following records for the auxiliary boiler:
   - The hours of operation.
   - The date, start time, end time and amount of fuel used for any period when fuel oil is burned.

8. The owner/operator shall secure a provision in the steam purchase contract with Colfax Rendering that requires Colfax to notify Pawtucket Power Associates whenever the steam boiler at the Colfax Rendering Plant is about to be started up or shut down.

9. The owner/operator shall maintain a time log for the facility and the Colfax Rendering Plant that shows on a continuous basis each of the following operations and their simultaneity:
   - Turbine baseload operation and fuel used
   - Turbine start-up operation (full speed/no load) and fuel used
   - Auxiliary boiler operation and fuel used
   - Colfax Rendering Plant steam boiler operation

10. The owner/operator shall notify the Division of the anticipated date of the initial start-up not more than 60 days nor less than 30 days prior to such date.

11. The owner/operator shall notify the Division in writing of the date construction of the facility commenced no later than 30 days after such date.

12. The owner/operator shall notify the Division in writing of the date of actual initial start-up no later than fifteen days after such date.

13. The owner/operator shall notify the Division in writing of any physical or operational change to the facility which may increase the emission rate of any air pollutant. Such notification shall include:
   - Information describing the nature of the change.
   - Information describing any planned changes to the air pollution control system.
   - Information describing the effect of the change on the throughput capacity of the facility.

- The expected completion date of the change.

Such change shall be consistant with the appropriate regulations and be subject to approval of the Director.

14. The owner/operator shall notify the Division in writing of the date upon which initial performance testing of the continuous emission monitors commences at least 30 days prior to such date.

15. The owner/operator shall submit a written report of excess emissions as measured by a continuous emission monitor for every calendar quarter. All quarterly reports shall be received no later than 30 days following the end of each calendar quarter and shall include the following information:
    - The date and time of commencement and completion of each time period of excess emissions and the magnitude of the excess emissions.
    - Identification of the suspected reason for the excess emissions and any corrective action taken.
    - The date and time period any continuous emission monitor was inoperative, except for zero and span checks and the nature of system repairs or adjustments.

    When none of the above items have occurred, such information shall be stated in the report.

16. All records required in this permit shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Division upon request.

G. Other Permit Conditions

1. There shall be no bypassing of the air pollution control equipment during start-up, operation or shutdown.

2. An operation and maintenance plan for the facility must be submitted to the Division at least 180 days prior to start-up of the facility.

3. The facility shall be designed, constructed and operated consistent with the representation of the facility in the construction permit application.

4. A malfunction of any air pollution control equipment that would result in the exceedance of any emission limitation in this permit will necessitate the shutdown of the unit(s) which would cause the exceedance. The unit(s) must remain shutdown until the malfunction has been identified and corrected.

5. Employees of the Division and its authorized representatives shall be allowed to enter the facility at all times for the purpose of inspecting any air pollution source, investigating any condition it believes may be causing air pollution or examining any records required to be maintained by the Division.

6. The owner/operator shall have each delivery of fuel oil analyzed for sulfur content. The fuel oil must be sampled and analyzed according to ASTM methods which have the prior approval or are required by the Director. The owner/operator shall maintain and preserve indefinitely the records for each fuel oil delivery, its sampling and analysis.

7. This facility is subject to the requirements of the Federal New Source Performance Standards 40 CFR 60, Subparts A (General Provisions) and GG (Stationary Gas Turbines). Compliance with all applicable provisions of these regulations is required.

8. Construction access and circulation routes shall be provided a temporary pavement surface.

9. All other construction related travel routes, exposed or excavated areas, shall be watered down as frequently as necessary to minimize dust.

10. Construction vehicles transporting loose aggregate shall be covered with a tarpaulin or similar dust resistant membrane.

11. Construction vehicle operating speeds shall be controlled to minimize generation of dust.

12. All construction related open storage areas and/or piles of soil, aggregates or any other dust producing material shall be covered or watered down as necessary to prevent generation of dust.

13. Any spillage from construction trucks or other construction equipment on any public street shall be removed promptly.

14. The natural gas fired in each turbine shall be analyzed daily for nitrogen and sulfur content as specified in 40 CFR 60.334 and 60.335 unless an alternative monitoring plan is approved by the US EPA Region I.

H. Startup/Shutdown Conditions and Initial Commissioning

1. Turbine startup/shutdown shall be defined as that period of time from initiation of combustion turbine firing until the unit reaches steady-state operation at 85% to 100% load conditions. This period shall not exceed 60 minutes for a hot start, nor 180 minutes for a cold start. A cold start shall be defined as startup when the turbine has been down for more than 24 hours.

2. Initial turbine commissioning shall be defined as the first 200 hours of combustion turbine operation following initial startup, or to commercial acceptance, whichever is less.

3. The emission limitations of conditions A.1 and A.2 shall not apply during turbine startup/shutdown conditions or the turbine's initial commissioning.

4. The owner/operator shall submit to the Division for review and approval at least 180 days prior to startup the procedures to be followed during turbine startup/shutdown conditions and initial turbine commissioning. The procedures shall be designed to minimize the emission of air contaminants to the maximum extent practical.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

DIVISION OF AIR AND HAZARDOUS MATERIALS
291 Promenade Street
Providence, R. I. 02908-5767

23 January 1989

Mr. Carlos Riva
Ocean State Power
110 Tremont Street
Boston, MA 02108

Dear Mr. Riva:

The Department of Environmental Management, Division of Air and Hazardous Materials has reviewed the application of Ocean State Power seeking a Prevention of Significant Deterioration (PSD) permit for the construction of a 500 MW, gas turbine based, combined cycle electric generation facility in Burrillville, Rhode Island. Public hearings were held with respect to the application on 17 November 1988, and on 13 December 1988 the Hearing Officer in the matter issued a Decision and Order.

On the basis of the Hearing Officer's 13 December 1988 Decision and Order, it has been determined that the facility, as proposed, is capable of complying with the applicable air pollution control rules and regulations of the Department of Environmental Management.

Therefore, pursuant to this Decision and Order, a PSD permit is issued to Ocean State Power subject to the attached permit conditions and emission limitations (RI-PSD-1).

Please be reminded that Condition G.15 of the enclosed permit requires Ocean State Power to file applications for approval to construct/install and receive approval prior to construction/installation of the following equipment:

1. The combustion turbine(s)
2. The heat recovery steam generator(s)
3. The auxiliary boiler
4. The SCR system(s)

Each application must be filed at least 120 days prior to the anticipated date of construction/installation of the specific piece of equipment.

If there are any questions concerning this permit, please contact me at (401) 277-2808.

Very truly yours,

Douglas L. McVay

Douglas L. McVay, Prin. Engineer
Division of Air & Hazardous Materials

DMV/kz

cc: w/attachments
Lynne Hamjian - USEPA Region I
Kathleen Lanphear - DEM
Don Squires, Tom Cusson - MA DEQE
Burrillville Town Council President
David Laferriere
Eugenia Marks
Doug Hartley - EFSB

ocen-dm/k18

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
DIVISION OF AIR AND HAZARDOUS MATERIALS

Permit Conditions and Emissions Limitations
OCEAN STATE POWER

RI - PSD - 1

A. Emission Limitations - Turbines

1. Natural Gas Firing

a. Nitrogen oxides (as nitrogen dioxide (NO_2)
   1. The concentration of nitrogen oxides in each turbine exhaust flue shall not exceed 9 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).
   2. The emission rate of nitrogen oxides from each turbine exhaust flue shall not exceed 37.4 lbs/hr. when both turbines in a two-turbine combined cycle system are operating, nor exceed 53.0 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

b. Carbon Monoxide (CO)
   1. The concentration of carbon monoxide in each turbine exhaust flue shall not exceed 25 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).
   2. The emission rate of carbon monoxide from each turbine exhaust flue shall not exceed 46.8 lbs/hr. when both turbines in a two-turbine combined cycle system are operating, nor exceed 64.8 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

c. Sulfur Dioxide (SO_2)
   1. The emission rate of sulfur dioxide from each turbine exhaust flue shall not exceed 0.0027 lbs per million BTU heat input (HHV) or a maximum of 3.1 lbs/hr., whichever is more stringent, when both turbines in a two turbine combined cycle system are operating.

   2. The emission rate of sulfur dioxide from each turbine exhaust flue shall not exceed 0.0027 lbs per million BTU heat input (HHV) or a maximum of 4.2 lbs/hr., whichever is more stringent, when only one turbine in a two turbine combined cycle system is operating.

d. Particulate Matter
   1. The emission rate of particulate matter from each turbine exhaust flue shall not exceed 0.01 lbs per million BTU heat input (HHV) or a maximum of 11.5 lbs/hr, whichever is more stringent, when both turbines in a two turbine combined cycle system are operating.

   2. The emission rate of particulate matter from each turbine exhaust flue shall not exceed 0.01 lbs per million BTU heat input (HHV) or a maximum of 18 lbs/hr., whichever is more stringent, when only one turbine in a two turbine combined cycle system is operating.

e. Total Nonmethane Hydrocarbons (NMHC)
   1. The concentration of total nonmehtane hydrocarbons in each turbine exhaust flue shall not exceed 4.1 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).

   2. The emission rate of total nonmethane hydrocarbons from each turbine exhaust flue shall not exceed 4.7 lbs/hr. when both turbines in a two turbine combined cycle system are operating, nor exceed 7.2 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

f. Ammonia (NH_3)
   1. The concentration of ammonia in each turbine exhaust flue shall not exceed 30 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).

   2. The emission rate of ammonia in each turbine exhaust flue shall not exceed 54 lbs/hr. when both turbines in a two turbine combined cycle system are operating, nor exceed 65 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

2. Oil Firing

a. Nitrogen Oxides (as nitrogen dioxide (NO_2)
   1. The concentration of nitrogen oxides in each turbine exhaust flue shall not exceed 42 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average)
   2. The emission rate of nitrogen oxides from each turbine exhaust flue shall not exceed 190.3 lbs/hr.

b. Carbon Monoxide (CO)
   1. The concentration of carbon monoxide in each turbine exhaust flue shall not exceed 32 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average)
   2. The emission rate of carbon monoxide from each turbine exhaust flue shall not exceed 81.7 lbs/hr.

c. Sulfur Dioxide (SO_2)
   1. All fuel oil burned in any turbine shall contain 0.3 percent sulfur or less by weight.
   2. The emission rate of sulfur dioxide from each turbine exhaust flue shall not exceed 349.7 lbs/hr.

d. Particulate Matter
   The emission rate of particulate matter from each turbine exhaust flue shall not exceed 0.01 lbs per million BTU heat input (HHV) or a maximum of 11.5 lbs/hr whichever is more stringent.

e. Total Nonmethane Hydrocarbons (NMHC)
   1. The concentration of total nonmethane hydrocarbons in each turbine exhaust flue shall not exceed 7.2 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).

   2. The emission rate of total nonmethane hydrocarbons from each turbine exhaust flue shall not exceed 10.3 lbs/hr.

B. Emission Limitations - Duct Burners

1. Natural Gas Firing

a. Nitrogen Oxides (as nitrogen dioxide (NO_2)
The emission rate of nitrogen oxides from each duct burner shall not exceed 0.1 lbs per million BTU heat input (HHV) or a maximum of 38 lbs/hr., whichever is more stringent.

b. Particulate Matter
The emission rate of particulate matter from each duct burner shall not exceed 0.03 lbs per million BTU heat input (HHV) or a maximum of 11.4 lbs/hr., whichever is more stringent.

c. Sulfur dioxide (SO_2)
The emission rate of sulfur dioxide from each duct burner shall not exceed 0.2 lbs per million BTU heat input (HHV) or a maximum of 76 lbs/hr., whichever is more stringent.

C. Operating Requirements

1. Oil use shall be limited to that needed to maintain oil system readiness and emergency conditions such as a natural gas supply curtailment or a breakdown of the delivery system that make it impossible to fire natural gas in the combustion turbine. In no event shall the hours of operation on oil exceed 1200 hours per turbine in any consecutive 12 month period.

2. The duct burners shall be fired with natural gas only.

3. The auxillary boiler shall be operated only during periods when all of the combustion turbines are not operating or during startup periods. Operation during startup periods shall not exceed 3 hours.

4. Visible emissions from any stack at this facility shall not exceed 10% opacity except for a period or periods aggregating no more than three minutes in any one hour.

D. Continuous Monitors

1. Continuous emission monitoring equipment shall be installed, operated and maintained for opacity, nitrogen oxides, carbon monoxide and oxygen.

2. The continuous monitors must satisfy EPA performance specifications in 40 CFR 60, Appendix B.

3. Performance specifications, monitor location, calibration and operating procedures and quality assurance procedures for each monitor must be submitted to the Division for review and approval at least 180 days prior to expected start-up.

4. All data shall be monitored and recorded continuously.

5. Natural gas and fuel oil flows to each turbine and the duct burners shall be continuously measured and recorded.

6. A method for monitoring and recording ammonia concentrations in the turbine flue gases shall be proposed for the Division's approval and implementation.

7. Catalyst bed temperature shall be continuously measured and recorded.

8. Continuous emission monitoring equipment for opacity shall be installed, operated and maintained on the auxiliary boiler.

9. The facility shall have the capability of transmitting all of the collected continuous monitoring data to the Division's office via a telemetry system. The owner/operator must provide all of the necessary funds for installation and operation of this equipment. A plan for accomplishing this must be submitted to the Division for review and approval prior to installation of the equipment and at least 180 days prior to expected start-up. This plan shall also define procedures to test and protect the integrity of transmitted data.

E. Stack testing

1. Within 180 days of start-up, initial performance testing shall be conducted for each turbine. Performance testing shall be conducted for nitrogen oxides, carbon monoxide, particulate matter (total and PM-10), non methane hydrocarbons, sulfur dioxide, and ammonia.

2. A stack testing protocol shall be submitted to the Division for review and approval prior to the performance of any stack tests. The owner/operator shall provide the Division at least 60 days prior notice of any performance test.

3. All test procedures used for stack testing shall be approved by the Division prior to the performance of any stack tests.

4. The owner/operator shall install any and all test ports or platforms necessary to conduct the required stack testing, provide safe access to any platforms and provide the necessary utilities for sampling and testing equipment.

5. Initial performance testing shall be conducted when burning natural gas and when burning fuel oil. All testing shall be conducted under operating conditions deemed acceptable and representative for the purpose of assessing compliance with the applicable emission limitation.

6. A final report of the results of stack testing shall be submitted to the Division no later than 45 days following completion of the testing.

7. All stack testing must be observed by the Division or its authorized representatives to be considered acceptable.

F. Recordkeeping and Reporting

1. The owner/operator shall maintain a record of all measurements, performance evaluations, calibration checks, and maintenance or adjustments for each continuous monitor.

2. The owner/operator must notify the Division no later than one hour after a violation of any emission limitation is discovered. Notification shall include:
   - Identification of the emission standard violated
   - Suspected reason for the violation
   - Corrective action taken or to be taken
   - Anticipated length of violation

3. The owner/operator must provide a written report within 5 days of any violation of an emission standard. This report shall, at a minimum provide the information required in F.2.

4. The owner/operator must notify the Division no later than one hour after the discovery that a continuous emission monitor has malfunctioned. Notification shall include:
   - The type and location of the malfunctioning monitor
   - The suspected reason for the malfunction
   - The corrective action taken or to be taken
   - The anticipated time needed to repair or replace the monitor.

5. The owner/operator shall notify the Division of any anticipated noncompliance with the terms of this permit or any other applicable air pollution control rules or regulations.

6. The owner/operator shall maintain the following records for each turbine:
   - The hours of operation, including any start up, shut down or malfunction in the operations of the facility.
   - The date, start time, end time and amount of fuel used for any period when fuel oil is burned.
   - Any malfunction of the air pollution control system.

7. The owner/operator shall notify the Division of the anticipated date of the initial start-up not more than 60 days nor less than 30 days prior to such date.

8. The owner/operator shall notify the Division in writing of the date construction of the facility commenced no later than 30 days after such date.

9. The owner/operator shall notify the Division in writing of the date of actual initial start-up no later than fifteen days after such date.

10. The owner/operator shall notify the Division in writing of any physical or operational change to the facility which may increase the emission rate of any air pollutant. Such notification shall include:
    - Information describing the nature of the change.
    - Information describing any planned changes to the air pollution control system.

- Information describing the effect of the change on the throughput capacity of the facility.
- The expected completion date of the change.

Such a change shall be consistent with the appropriate regulations and be subject to approval of the Director.

11. The owner/operator shall notify the Division in writing of the date upon which initial performance testing of the continuous emission monitors commences at least 30 days prior to such date.

12. The owner/operator shall submit a written report of excess emissions as measured by a continuous emission monitor for every calendar quarter. All quarterly reports shall be received no later than 30 days following the end of each calendar quarter and shall include the following information:
    - The date and time of commencement and completion of each time period of excess emissions and the magnitude of the excess emissions.
    - Identification of the suspected reason for the excess emissions and any corrective action taken.
    - The date and time period any continuous emission monitor was inoperative, except for zero and span checks and the nature of system repairs or adjustments.

    When none of the above items have occurred, such information shall be stated in the report.

13. All records required in this permit shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Division upon request.

G. Other Permit Conditions

1. There shall be no by passing of the air pollution control equipment during start-up, operation or shutdown during natural gas firing.

2. An operation and maintenance plan for the facility must be submitted to the Division at least 180 days prior to start-up of the facility.

3. The facility shall be designed, constructed and operated consistent with the representation of the facility in the PSD permit application.

4. A malfunction of any air pollution control equipment that would result in the exceedance of any emission limitation in this permit will necessitate the shut down of the unit(s) which would cause the exceedance. The unit(s) must remain shutdown until the malfunction has been identified and corrected.

5. Employees of the Division and its authorized representatives shall be allowed to enter the facility at all times for the purpose of inspecting any air pollution source, investigating any condition it believes may be causing air pollution or examining any records required to be maintained by the Division.

6. The owner/operator shall have each delivery of fuel oil analyzed for sulfur content. The fuel oil must be sampled and analyzed according to ASTM methods which have the prior approval or are required by the Director. Records of the fuel oil analyses shall be maintained by the owner/operator.

7. This facility is subject to the requirements of the Federal New Source Performance Standards 40 CFR 60, Subparts A (General Provisions), Da (Electric Utility Steam Generating Units) and GG (Stationary Gas Turbines). Compliance with all applicable provisions of these regulations is required.

8. Construction access and circulation routes shall be provided a temporary crushed gravel or pavement surface.

9. All construction related travel routes, exposed or excavated areas, shall be watered down as frequently as necessary to minimize dust.

10. Construction vehicles transporting loose aggregate shall be covered with a tarpaulin or similar dust resistant membrane.

11. Construction vehicle operating speeds shall be controlled to minimize generation of dust.

12. All construction related open storage areas and/or piles of soil, aggregates or any other dust producing material shall be covered or watered down as necessary to prevent generation of dust.

13. Any spillage from construction trucks or other construction equipment on any public street shall be removed promptly.

14. The natural gas fired in each turbine shall be analyzed daily for nitrogen and sulfur content as specified in 40 CFR 60.334 and 60.335 unless an alternative monitoring plan is approved by the USEPA Region I.

15. The applicant must file applications for approval to construct/install and receive approval prior to construction/installation of the following equipment:

    (i) the combustion turbine(s)
    (ii) the heat recovery steam generator(s)
    (iii) the auxiliary boiler
    (iv) the SCR system(s)

    Each application must be submitted at least 120 days prior to the anticipated date of construction/installation.

16. During the first year of operation of the facility, the owner/operator shall sample and analyze the cooling tower water influent for total chromium and hexavalent chromium. Samples shall be taken daily and composited and analyzed monthly. The results of this analysis shall be submitted to the Division quarterly. The Division may continue this sampling and analysis requirement beyond the first year's operation at it's discretion, in consideration of the results.

H. Startup/Shutdown Conditions and Initial Commissioning

1. Turbine startup/shutdown shall be defined as that period of time from initiation of combustion turbine firing until the unit reaches steady state operation at 75-100 percent load conditions. This period shall not exceed 60 minutes.

2. Initial turbine commissioning shall be defined as the first 200 hours of combustion turbine operation following initial startup or to commercial acceptance whichever is less.

3. The emission limitations of Conditions A.1 and A.2 shall not apply during turbine startup/shutdown conditions or each turbine's initial commissioning.

4. The owner/operator shall submit to the Division for review and approval, at least 180 days prior to startup, the procedures to be followed during turbine startup/shutdown conditions and initial turbine commissioning. The procedures shall be designed to minimize the emission of air contaminants to the maximum extent practical.

I. Nitrogen oxides during oil firing

1. Every three years, from the date of issuance of this permit, the Division shall evaluate the evidence concerning the potential for downstream corrosion of the heat recovery steam generator during oil firing with an activated SCR system. If the Division determines that there is sufficient evidence to show that SCR use during oil firing will not lead to downstream corrosion of the heat recovery steam generator then the Division will modify Condition A.2.a to require the use of the SCR system during oil firing.

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