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.

preli-dm/L13

OCEAN STATE POWER
110 TREMONT STREET, BOSTON, MASSACHUSETTS 02108 TELEPHONE (617) 451-1103 TELEX: 95-1459

July 7, 1988

Mr. Douglas McVay, P.E.
Division of Air and Hazardous Materials
R.I. Department of Environmental Management
291 Promenade Street
Providence, RI 02908-5767

Dear Mr. McVay:

Attached is a document entitled, "NO_x Cost Control Assessment" which presents a BACT cost analysis for OSP for four levels of NO_x control, i.e., uncontrolled emissions of 155ppmv, water injection to 42ppmv, a "quiet" combustor rate of 25ppmv and an SCR rate of 9ppmv. The costs and technical data presented are more accurate and more inclusive than those originally submitted prior to the selection of GE as the turnkey contractor.

This cost analysis should be used in your review of BACT for NO_x control. We will be pleased to review this analysis with you at your earliest convenience.

Sincerely,

Neil Collins

J. O'Neill Collins,
Director, Environmental Affairs

/md

cc: T. Getz, RIDEM
C. Riva
R. Sherman, TC&G
B. Ormerod, GE
K. Vassar, Bechtel

Ref: MDOS0155

07-Jul-88

OCEAN STATE POWER
- 500 MW -
NOx COST CONTROL ASSESSMENT

($ IN 000,000'S)

PARTS PER MILLION VOLUME	155	42	25	9
CAPITAL COST ANALYSIS:				
DIFFERENTIAL COST OVER BASE (1)	0.00	3.60	12.66	24.96
FINANCING COST (2)	0.00	0.72	2.53	4.99
	0.00	4.32	15.19	29.95
OPERATING COSTS:				
OPERATION AND MAINTENANCE (3)	0.00	0.10	0.20	4.40
ENGINEERING COST:				
HEAT RATE (HHV) (4)	8110	8278	8376	8321
AVAILABILITY EXPECTED (5)	80.00%	80.00%	80.00%	75.00% (6)
ANNUAL ENERGY LOSS (BBTU) (7)	0	589	932	786
COST IMPACT @ $2/MMBTU (8)	0.00	1.18	1.86	1.57

ANNUAL DIFFERENTIAL COST

ANNUAL DEPRECIATION (9)	0.00	0.22	0.76	1.50
ANNUAL FINANCING (10)	0.00	0.54	1.90	3.74
OPERATION AND MAINTENANCE	0.00	0.10	0.20	4.40
HEAT RATE IMPACT	0.00	1.18	1.86	1.57
AVAILABILITY IMPACT (11)	0.00	0.00	0.00	13.14
TOTAL COST	0.00	2.03	4.72	24.35
INCREMENTAL COST	0.00	2.03	2.69	19.63

COST BENEFIT ANALYSIS
NOx TONS REMOVED

(ACTUAL DOLLARS)

NOx REMOVAL (12)				
TONS EMITTED	7312	2144	1344	420
TONS REMOVED	0	5168	5968	6892
INCREMENTAL TONAGE REMOVED	0	5168	800	924
COST OF NOx REMOVAL				
COST/TON REMOVED	$0	$393	$791	$3,533
INCREMENTAL COST/TON REMOVED (13)	$0	$393	$3,362	$21,245
NET REMOVAL AND COST OF SCR				
TONS REMOVED (14)				6350
INCREMENTAL TONNAGE REMOVED				382
COST/TONS REMOVED				$3,835
INCREMENTAL COST/TON REMOVED				$51,391

NOTES:

1. Costs presented include GE power train costs only and exclude cost of water and oil pipelines.

2. Construction financing cost is assumed to be 20% of contract cost over a 27 month construction period.

3. Annual operational costs include estimated costs of \$100,000 (at 42ppmv), \$200,000 (at 25ppmv) and \$1.1 million (at 9ppmv) for chemical usage in water treatment and ammonia for catalyst operation. SCR related maintenance costs of \$3.3 million include cost of catalyst replacement at a capital cost of \$1.54 million/HRSG/2 years (with 4 HRSG = \$3.08 million/yr) and labor cost of 1,500 hours x \$75/HRSG/2 years (at 4 HRSG = \$.22 million/yr).

4. HHV as 1.105 x LHV presented in GE specifictions.

5. Expected availability is based on the fact that the OSP plant is most likely to operate at contract base rate of 80%. This is consistant with power sales contracts, financing and federal and state rate estimates and assumptions.

6. The 5% availability loss caused by SCR includes scheduled downtime of 6 weeks every 2 years for catalyst replacement for each HRSG (e.g., 6%) and 1% availability loss due to SCR unreliability, minus 2 weeks per year (2%) normally required for scheduled maintenance.

7. Annual Energy Loss in BBTU = Heat Rate differential x Total Power Output x Number of hours operated x appropriate conversion factor to BBTU.

8. Heat Rate Loss Cost is calculated as Annual Btu Loss x the \$2.00/MMBtu assumed price of natural gas.

9. Depreciation at 20 year plant life, as 1/20 x Total Capital Cost Differential.

10. Annual financing is calculated as 12.5% of the Capital Cost Differential, per current project financing costs.

11. The cost of availability loss due to 5% SCR availability loss is the cost of replacement power, by oil-fired generation, at \$.08/kw (e.g. 20-25% above OSP's consumer rate) minus the variable cost for OSP to produce power at \$.02/kw; e.g., .05 x 8760 x 500 MW x 1000 kw/MW x \$.06.

12. Plant emissions are derived from GE calculations for the 500 MW OSP plant, base load, natural gas fired, at ISO conditions. These include an expected 80% availability rate (e.g.,7,008 hours of operation at base load 500 MW), due to the fact that the OSP plant is most likely to operate at contract base rate of 80% consistent with sales contracts, financing and federal and state rate estimates and approvals are made. See note 13 for comparison of cost differences for 8760 hours of operation versus 7008 hours.

13. For comparison purposes, at 8760 hours of power production, assuming no maintenance time, etc., the incremental cost of NO_x removal for 25ppmv would be approximately \$2,000 and for 9ppmv the incremental cost would be \$16,000 without consideration of oil fired generation for the lost 5% availability and \$30,000 when considering NO_x produced by replacement power.

14. NO_x production by an oil fired facility, replacing the 5% lost generation due to SCR availability loss is calculated per USEPA Guideline "AP-42" as 0.45 lbs. NO_x/1,000,000 Btu x 1 ton/2,000 lbs. x 11,000 Btu/kw hr x 500,000 kw x 8760 hrs x .05 availability loss = 542 tons NO_x/year.

Ref: MDOS0148