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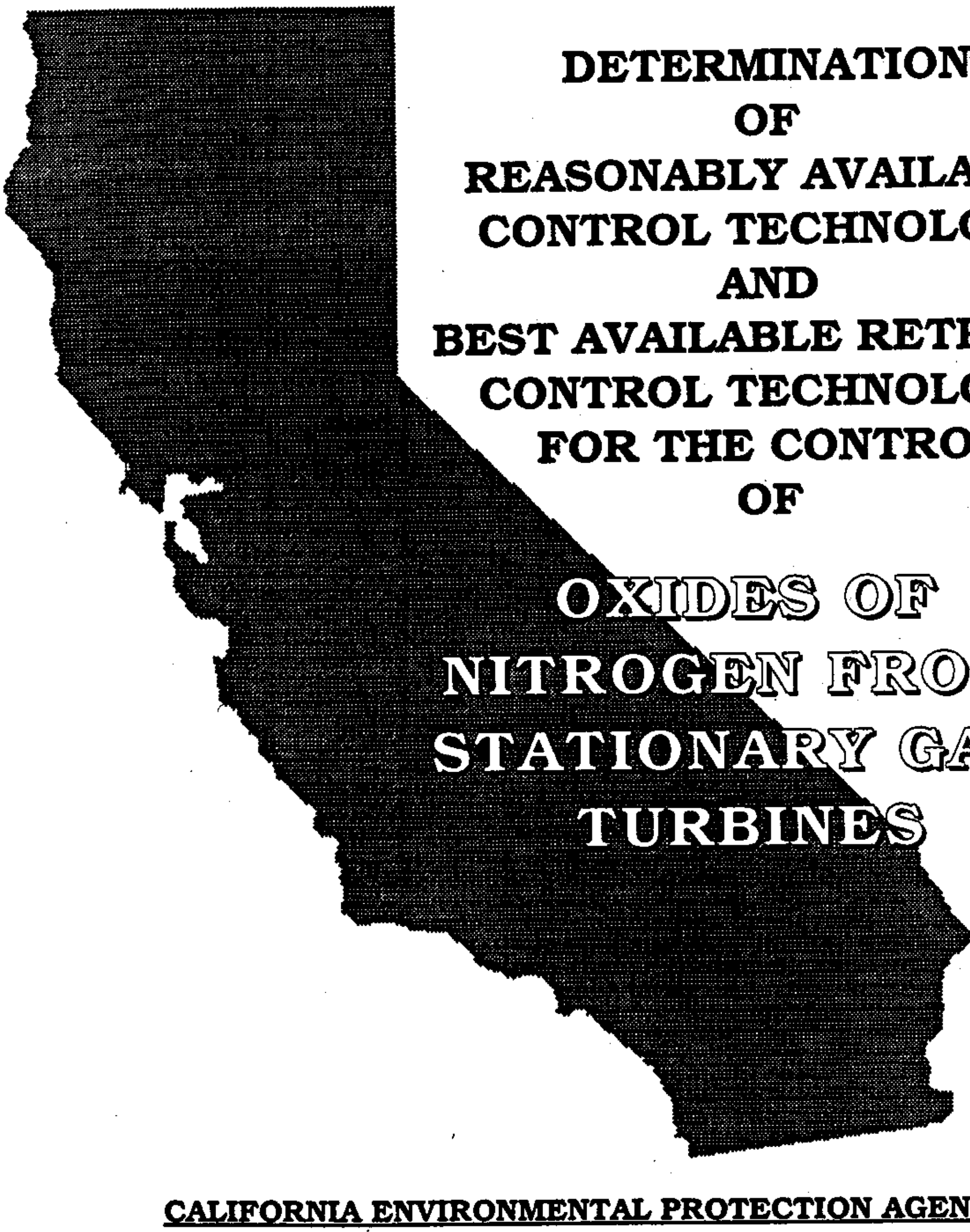

DETERMINATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY AND BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY FOR THE CONTROL OF

OXIDES OF NITROGEN FROM STATIONARY GAS TURBINES

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

Air Resources Board

RACT/BARCT

ERRATA SHEET

The following changes are to be made to the report <u>Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines</u>, May 18, 1992.

1. Page 4, Table 1, Test Methods: Delete "Oxygen - ARB Method 422"

2. Page A.6, VI. Test Methods, Line 2, Delete: "Oxygen content of the exhaust gas shall be determined by using ARB Method 422, Determination of Volatile Organic Compound Emissions from Stationary Sources."

State of California
AIR RESOURCES BOARD

DETERMINATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY AND BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY FOR THE CONTROL OF OXIDES OF NITROGEN FROM STATIONARY GAS TURBINES

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The Technical Review Group
of the
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May 18, 1992

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INTRODUCTION

This report presents the proposed determination of Reasonably Available Control Technology (RACT) and Best Available Retrofit Control Technology (BARCT) for oxides of nitrogen compounds (NOx) from stationary gas turbine operations. This report also presents the basis for the determination, an overview of the control technology and cost-effectiveness, and the associated economic and other impacts. This determination is applicable to stationary gas turbines which have a power rating of 0.3 megawatts (MW) or greater.

A gas turbine is an engine which consists of a compressor, a combustor, and a power turbine. The compressor provides pressurized air to the combustor where fuel is burned. Hot combustion gases leave the combustor and enter the turbine section. In the turbine section, the gases are expanded across the power turbine blades to rotate one or more shafts, which power the compressor and electric generator.

Gas turbines are generally used to produce electricity. Electric utilities use gas turbines in the combined cycle configuration, which has a 45-52% fuel conversion efficiency, to supplement base load operations on a full-time basis. Utilities also use the simple cycle configuration, which has a 25-41% fuel conversion efficiency, on an intermittent basis to cover peak demand. Cogenerators use gas turbines in the cogeneration configuration to produce both electricity, for personal use or for sale, and useful thermal energy. Of the three, simple cycle gas turbines are the least efficient because the hot combustion gases that leave the turbine blades go immediately out the stack. In contrast, exhaust gases from combined cycle turbines produce steam to generate electricity. Likewise, the exhaust gases from cogeneration gas turbines also produce steam, which in this case is used for heating or industrial processes.

There are two major types of gas turbines: industrial and aeroderivatives. Industrial gas turbines, which evolved from jet engines, generally have tubular or can combustors that are more durable and powerful (70-135 MW at the high end). Gas turbines manufactured by Asea Brown Boveri as well as the General Electric (GE) frame units are examples of industrial gas turbines. Aeroderivatives are modern jet engines used as ground installations, essentially unmodified. Aeroderivatives, which usually have annular combustors, are lightweight, compact, and less powerful (35-40 MW at the high end). However, they operate at much higher compression ratios and are thus more efficient. Aeroderivatives, by design, are also more suitable for future improvements such as intercooling, reheat, and chemical recuperation which together have the potential of increasing conversion efficiency above 60%. The GE LM2500 and LM5000 are examples of aeroderivative gas turbines.

In developing the proposed RACT and BARCT determinations for stationary gas turbines, the staff conducted two public workshops (May 20, 1991, and September 20, 1991) and reviewed several district rules, the Air Resources Board (ARB) Suggested Control Measure (SCM), and public comments submitted to the South Coast Air Quality Management District (SCAQMD) on control technology. Appendix B contains summaries of the district rules reviewed. Only one district rule, SCAQMD Rule 1134, is aimed specifically at gas turbines. This was determined to have the most stringent requirements for gas turbines and generally would require selective catalytic reduction (SCR) and water/steam injection to achieve the limits. The rule has optional limits which are slightly less restrictive but must be achieved without SCR. The less restrictive limitations are designed to encourage the development of new combustion technology. The proposed BARCT determination is based on SCAQMD Rule 1134.

The other district rules pertain to fuel burning and electric power generating equipment, which would also include gas turbines. Of these rules, San Bernardino County Rule 475 is the most stringent. However, district staff said that there are no gas turbines affected by the rule. Therefore, the RACT standards are based on San Diego County APCD Rule 68. Note, however, that the standard for oil-fired units has been modified to reflect limits achievable using water/steam injection rates comparable to those used with gas-fired units. These limits have been demonstrated to be achievable and are considered to be RACT.

I. RACT AND BARCT RECOMMENDATIONS

Staff recommends that the proposed determination presented in Appendix A be defined as RACT and BARCT for the control of NOx from stationary gas turbines. Table 1 summarizes the major requirements of the proposed determination.

RACT

The proposed RACT determination requires compliance limits of 42 parts per million by volume (ppm) for gas-fired units and 65 ppm for oil-fired units. The determination is applicable to units greater than or equal to 0.3 MW. These limits are based on the use of water injection but can be met for some units with the use of low-NOx combustors.

BARCT

Large Turbines - The proposed BARCT limits for units greater than or equal to 10 MW are 9 ppm for gas-fired units and 25 ppm for oil-fired units. These limits are achievable with the use of SCR. Both limits are based on a thermal efficiency of 25 percent. Higher limits are allowed based on a demonstration of improved thermal efficiency. Alternative, less restrictive limits of 15 ppm for gas-fired units and 42 ppm for oil-fired units, corrected for efficiency, are proposed for units that do not use SCR. The alternative limits are considered to be technology-forcing but are included to promote the development of technologies that do not require the use of ammonia.

Mid-Sized Turbines - The proposed BARCT limits for units greater than or equal to 2.9 MW and less than 10 MW are 25 ppm, corrected for efficiency, for gas-fired units and 65 ppm for oil-fired units.

The limits for the mid-size units are based on the use of low-NOx combustors, severe water injection, or steam injection. Manufacturers of mid-size gas turbines are in various stages of development of dry low-NOx combustors. Some models of gas turbines are more difficult to retrofit with low-NOx combustors; older models are not being considered for retrofit. Manufacturers of mid-size units indicated that a 25 ppm limit could be achieved within the four year time frame with dry low-NOx combustors. Therefore, the determination for mid-sized turbines was designed to encourage the development of dry low-NOx combustors. One gas turbine manufacturer reported that the cost-effectiveness of new turbines using dry low-NOx combustors will be less than $1,000/ton. Even if the cost-effectiveness of retrofit applicators is twice this value, the technology would be more cost-effective than SCR. In some cases, water injection may be more cost-effective.

Lower limits would require the use of SCR. The capital cost of an SCR unit designed for 9 ppm for mid-size units ranges from 40-60 percent of the capital cost of the gas turbine. The capital cost for retrofit with low-NOx combustors is 20-40 percent of the cost of the gas turbine. The 25 ppm standard was chosen because of the high capital cost of SCR and to encourage the development of low-NOx combustor technology.

Table 1

Summary of RACT and BARCT Determinations for the Control of Oxides of Nitrogen from Stationary Gas Turbines

Standards

Unit Size Rating (Megawatts)	Compliance Limits NOx, ppm at 15% Oxygen Gas[a]	Oil[b]
-----RACT-----		
0.3 and Greater	42	65
-----BARCT-----		
≥ 0.3 and < 2.9 and Units ≥ 4, Operating < 877 hrs/yr	42	65
≥ 2.9 and < 10	$25 \times \frac{EFF}{25}$	65
≥ 10, No SCR	$15 \times \frac{EFF}{25}$	$42 \times \frac{EFF}{25}$
≥ 10, With SCR	$9 \times \frac{EFF}{25}$	$25 \times \frac{EFF}{25}$

[a] Gas includes natural, digester, and landfill.
[b] Oil includes kerosene, jet, and distillate. Effective October 1, 1993, the sulfur content of the oil shall be less than 0.05% by weight.

Exemptions: Research Testing
Firefighting and/or flood control
Pipeline gas turbines where shown to be technologically or economically infeasible
Emergency standby units operated less than 200 hours per calendar year
Units less than 4 MW and operated less than 877 hrs/yr

Administrative Requirements: Compliance Schedule
Emission Control Plan
Continuous Monitoring System
Recordkeeping

Test Methods: NOx - ARB Method 20
Oxygen - ARB Method 422
HHV - ASTM D240-87 or ASTM D2382-88 for oil;
ASTM D3588-91, ASTM D1826-88, or ASTM D1945-81 for gas

Small Turbines - The proposed BARCT limits for units less than 2.9 MW and greater than or equal to 0.3 MW are 42 ppm for gas-fired units and 65 ppm for oil-fired units. These limits are identical to RACT requirements. RACT limits also apply to units with low capacity factors greater than or equal to 4 MW.

SULFUR CONTENT

The sulfur content of the oil is limited to 0.05% by weight. Both state and federal regulations require the use of low-sulfur oil for motor vehicles beginning October 1, 1993. In addition, the SCAQMD also requires the use of low-sulfur oil. Therefore, this fuel should be widely available throughout the state.

EXEMPTIONS

An exemption from RACT and BARCT would be provided for laboratory units used for research and testing to advance gas turbine technology, pipeline gas turbines shown to be technologically or economically infeasible to retrofit, emergency units operating less than 200 hours per year, units used for firefighting or flood control, and units less than four MW and operated less than 877 hours per year.

An exemption not exceeding two hours is also allowed for the startup thermal stabilization period. However, if deemed necessary, the APCO may include a shut-down period as part of the thermal stabilization period.

Districts may choose to add low-usage RACT and BARCT exemptions for larger units to maintain a lower cost-effectiveness. The districts may also choose to exempt units that have been issued an Authority to Construct to install an innovative control technology that may achieve levels less stringent than the proposed BARCT determination but have advanced the state-of-the-art technology. The Authority to Construct should be dated prior to May 1, 1992.

The determination also includes a reserved section for the purpose of including specific exemptions that the Air Pollution Control Officer (APCO) finds are necessary to ensure that the rule is technologically feasible and cost-effective.

COMPLIANCE SCHEDULE

The recommended compliance schedule calls for submittal of emission control plans in two years from the date of district rule adoption and final compliance in four years from the date of district rule adoption.

MONITORING REQUIREMENTS

The proposed determination requires continuous monitoring devices which measure parameters necessary to determine compliance such as gaseous or liquid flow rates and operation time. In addition, BARCT requires units 10 MW and over to be equipped with continuous NOx monitoring systems.

II. CONTROL TECHNOLOGY

Combustion of fossil fuels generates NOx emissions from the oxidation of fuel-bound nitrogen (fuel NOx) and from the oxidation of nitrogen in the air (thermal NOx). Fuel NOx generation is a function of the nitrogen content of the fuel. The nitrogen and sulfur contents of liquid fuels can both be reduced through hydrotreating at the refinery. Thermal NOx generation is a function of the flame temperature and residence time. Combustion strategies for controlling thermal NOx are based on lowering the combustor temperature. Two methods of control that are currently available for gas turbines are diluent addition and dry low-NOx combustors. NOx emissions resulting from either fuel NOx or thermal NOx formation mechanisms can be controlled by using post combustion controls such as selective catalytic reduction. The use of methanol fuel is another alternative. All these methods will be discussed.

A. Water or Steam Injection

The addition of a diluent in the combustor will quench the flame and absorb heat, reducing the combustion temperature, thermal efficiency, and consequently the thermal formation of NOx. As a secondary benefit, the addition of diluents also increases the power output. Water or steam is typically used as diluents.

In most cases, the use of water or steam injection results in exhaust gas concentrations of 42 ppm NOx at 15% oxygen when firing on natural gas and 65 ppm when firing on oil without subjecting the internal parts to a rapid increase in wear (Schorr, 1990). Some aeroderivative gas turbines using water or steam injection can tolerate much higher injection rates without significant wear problems and can achieve NOx levels down to 25 ppm (San Diego Gas & Electric, 1990). Tests submitted to the SCAQMD by Wheelabrator demonstrated levels down to 12 ppm on a GE LM2500 (Wheelabrator, 1988). However, CO levels rose from 5 ppm to 170 ppm. VOC emissions were not reported by Wheelabrator, but an ASME paper reported VOC emissions to increase from 4 to 140 ppm (Burnham, 1986).

Simpson Paper submitted test results to the SCAQMD showing that their LM5000 can meet Rule 1134 requirements using steam injection. The source test levels for NOx and CO were 15 ppm and 48 ppm at 15 percent oxygen, respectively. No oxidation catalyst was required (Simpson Paper, 1991).

Excessive CO and VOC emissions can be controlled with oxidation catalysts. The size of the catalyst bed ranges from 11'x12'x3.7" to 15'x16'x3.7" for an LM2500 and 15'x15'x3.7" to 17'x18'x3.7" for an LM5000 (Harris, 1991). An SCR catalyst bed for similar sized units would be 24'x24'x1.6' to 27'x27'x1.5'. Bed shapes can be altered as long as the volume is the same.

Unlike aeroderivatives, industrial gas turbines generally cannot tolerate higher injection rates of water or steam. As water injection levels increase, these units experience a significant increase in dynamic pressure activity (noise) and engine wear. GE offers one model that can achieve NOx levels of 25 ppm on gas-fired units and 42 ppm on fuel oil-fired units using a combustor called a quiet combustor that is designed to tolerate higher levels of water without causing excessive dynamic pressure activity. However, there are no plans to make the quiet combustor available for other models (Schorr, 1990).

B. Dry Low-NOx Combustors

The use of dry low NOx combustors may be a means for gas turbines to achieve BARCT standards without the use of water/steam injection or selective catalytic reduction (SCR). These combustors are based on redistributing combustor airflow splits. The combustor is a two-stage premixed design with two flame zones, each receiving a constant fraction of the combustor air flow. Fuel flow is split between the two flame zones so that the amount of fuel fed into a stage is matched to the amount of air available at each operating condition.

Conventional combustors are diffusion controlled. The fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot-spots which produce more NOx. In contrast, dry low-NOx combustors generally operate in a premixed mode, where air and fuel are mixed before entering the combustor. In premixed flames, the reaction rate is limited more by chemical reaction rates rather than mixing rates. Thus the maximum flame temperature is better controlled by the air/fuel ratio. Consequently, NOx emissions can be controlled to a low of 9-25 ppm near full load, with resulting CO and total hydrocarbon (THC) emissions of 15-30 ppm and 10 ppm, respectively (Brooks, 1991; Maghon, 1990).

When firing on distillate oil, the combustor is designed to operate only in the diffusion mode with water injection. This mode of operation can generate a low NOx level of about 42-65 ppm. Siemens and Westinghouse are experimenting with firing on distillate oil in the premix mode and has achieved emissions down to 42 ppm and under (Maghon, 1990; Antos, 1991).

Low NOx combustors can be designed for any gas turbine. However, manufacturers plan to develop them only for certain popular models. Manufacturers expect to have these combustors available for retrofit on both industrial and aeroderivative gas turbines sometime between 1992-1995.

C. Selective Catalytic Reduction and Other Post Combustion Technologies

Selective catalytic reduction (SCR) is a post combustion control technology. In the SCR process, ammonia is injected into the exhaust gas stream where it reduces the NOx to molecular nitrogen, in the presence of a catalyst. The catalyst most commonly used is titanium dioxide, but it may instead be vanadium pentoxide, zeolite, or a noble metal. The catalyst operates ideally between 600-750° F and is normally placed inside the boiler. However, high temperature catalysts (up to 960° F) that can be placed upstream of the boiler have recently appeared on the market. These can be used in conjunction with air dilution to maintain the correct temperature range. UNOCAL in Brea, California, has installed a 4 MW cogeneration system with this type of catalyst control system. The system has been operating since November 1990.

SCR is capable of over 90 percent NOx removal and is often combined with water or steam injection to achieve very low levels when firing on gas (below 10 ppm). In remote areas where there is limited access to water, SCR without water injection may be preferred. An Authority To Construct has been filed with Kern County APCD for SCR on three proposed gas turbines for a gas pipeline compressor station located near Route 166 and I-5.

In a GE technical paper, the author expressed a concern about ammonium bisulfate emissions adhering to the walls of the heat recovery system when firing on oil (Boericke, GE). Ammonium bisulfate is formed by reaction of the sulfur in the feed with the ammonia slip stream. A certain amount of ammonia slip occurs when using SCR and is typically limited by permit conditions to less than 20 ppm. Because long term operational data for gas turbines operating on fuel oil is limited, the ammonium bisulfate issue is somewhat unresolved. However, we do not expect this to be a problem. For example, the Pfizer Plant at Adams, Massachusetts, has operated an IC engine powered cogeneration facility since November 1988 (Keller, 1989). The engine can operate on diesel fuel or dual fuel (natural gas and diesel). NOx emissions are controlled by over 90 percent with an SCR catalyst. The catalyst system has operated on more than 2000 hours of diesel operation without observable plugging, clogging or poisoning and an ammonia slip of less than 10 ppm. Locally, two ship diesel engines equipped with SCR NOx control systems have been regularly delivering steel to USS-Posco in Pittsburg, California, since February 1990 (Gibson, 1991). The SCR system, located between the engine and heat recovery boiler, has operated in the past on exhaust from marine diesel fuel with a nominal sulfur content of 0.04 percent without any reported problems with ammonium bisulfate formation. With the availability of very low sulfur fuel, the ship engines now operate on an oil with 0.006% sulfur supplied by Shell Oil Company. The operators have not experienced any problems with ammonia slip or with particulate matter formation in the heat recovery boiler downstream of the catalyst.

In the South Coast Air Basin and Ventura County, the sulfur content of motor vehicle diesel fuel has been controlled to a level of 0.05 weight percent since January 1985. This limit will be extended statewide beginning October 1, 1993. Therefore, low sulfur fuel oil should be readily available.

As an alternative to SCR, selective non-catalytic reduction (SNCR) is a post combustion technology that does not require a catalyst. Instead this technology depends upon temperatures over 1400°F to activate the reaction. In this process, a reducing agent such as urea or ammonia is injected into the exhaust duct to reduce the NOx to molecular nitrogen. This technology is about 50-80 percent efficient (Nalco, March 1990). However, we do not know of any gas turbines currently equipped with SNCR.

D. Methanol

The use of methanol fuel will result in lower NOx emissions than the use of fossil fuels. Methanol burns at a lower flame temperature, thus generating less NOx. Burning methanol fuel instead of natural gas in a gas turbine produces about a 60 percent reduction in NOx emissions. Burning methanol in a 10-20 percent water mixture produces about 80-90 percent reduction in NOx emissions. Emissions down to 9 ppm have been achieved. However, maximum power output may decrease. Also, carbon monoxide and hydrocarbon emissions tend to increase. The conversion to methanol fuel would require equipment modifications to accommodate the differences in properties between methanol and gas or fuel oil.

Two methanol demonstration projects have been performed in California over the past 13 years. The first was performed during 1978-1979 at the Southern California Edison Ellwood Energy Support Facility (EPRI, 1981). The retrofitted unit was one of a pair of TPM FT4C-1DF 25 MW units driving a common generator for peaking power. The system had accumulated 185 hours of total operating time before testing began and was considered in almost new condition. Methanol was fired for a total of 523 hours. The second demonstration was performed at the UC Davis cogeneration plant in 1984 (KVB, 1986). In operation since 1981, the cogeneration plant is powered by an Allison 3.2 MW gas turbine. The unit ran on methanol for 1036 hours.

Emission trends from both demonstration programs are tabulated in Tables 2 and 3. The trends indicate that both RACT and BARCT levels are achievable with methanol. However, the test data indicated that extremely low NOx emission levels can only be achieved at water injection rates greater than 0.3 water/fuel ratio and probably at reduced loads (91% load for the UCD installation) due to system flow capacity limits. The 26 MW unit produced lower CO and total hydrocarbon emissions when firing on methanol instead of natural gas. The 3.2 MW unit, however, produced lower NOx emissions, but CO emissions remained the same. When firing on methanol at half load, both units produced lower NOx emissions but higher CO and THC than at full load. For the 3.2 MW gas turbine, one factor contributing to the large increase in CO at high water injection rates and low loads may be the modification to the fuel nozzle to accept high flowrates. When firing on natural gas at half load, the 3.2 MW unit experienced no increase in CO emissions but a 30 percent reduction in NOx emissions compared to full load. The 26 MW gas turbine experienced lower NOx emissions but increased CO and THC emissions when reducing load to half and firing on natural gas.

Table 2

Emissions from a 26 MW Simple Cycle Gas Turbine

Load	Fuel	lb water / lb fuel	NOx (ppm, dry @ 15% oxygen)	CO (ppm, dry @ 15% oxygen)	THC (ppm, dry @ 15% oxygen)
Full	Methanol	0	50	35	5-10
Full	Methanol	0.2	20	95	15
Half	Methanol	0	35	NR[a]	25
Half	Methanol	0.2	15	NR	42
Full	Gas	0	140	150	200
Full	Gas	0.2	80	180	220
Half	Gas	0	85	200	300
Half	Gas	0.2	55	270	400

[a] NR means not recorded.

Table 3

Emissions from a 3.2 MW Cogeneration Gas Turbine

Load	Fuel	lb water / lb fuel	NOx (ppm, dry @ 15% oxygen)	CO (ppm, dry @ 15% oxygen)	THC (ppm, dry @ 15% oxygen)
Full	Methanol	0	38	22	NR[a]
Full	Methanol	0.2	17	20	NR
Full	Methanol	0.3[b]	12	20	NR
Half	Methanol	0	25	140[c]	NR
Half	Methanol	0.2	11	180	NR
Half	Methanol	0.3	13	175	NR
Full	Gas	0	105	20	NR
Half	Gas	0	70	20	NR

[a] NR means not recorded.

[b] Load was reduced to 91% to accommodate high water injection rate.

[c] High emissions are partly caused by enlargement of nozzle orifice to accommodate high flowrates.

III. COST-EFFECTIVENESS

A. Dry Low-NOx Combustors

Based on information from Solar Turbines (Swingle, 1991) and General Electric (Gessler, 1991), the capital cost to install low-NOx combustors on new units ranges from \$30-90/kw. The cost-effectiveness ranges from \$200-900/ton for an uncontrolled unit controlled to 42 ppm and from \$200-700/ton for control down to 25 ppm. Ultra-low NOx combustors, still under development to achieve 9 ppm, could be even more cost-effective. For units already controlled to 42 ppm, the cost-effectiveness would increase to \$1,300-3,200/ton. Retrofit costs would be higher, although no data are currently available.

B. Water Injection

Water injection requires a water injector nozzle, the installation of a piping system, metering equipment, and a water purification system. The SCAQMD Rule 1134 staff report (SCAQMD, 1989) gave a cost-effectiveness estimate (1986\$) for water injection control to a 42 ppm level of \$2,000/ton for units 2 MW and over and \$5,000/ton for units approximately 0.3 MW and operating full time. For units over 4 MW operating 1000 hours/year, the cost-effectiveness ranged from \$1800-\$4000/ton. The operating costs for water injection are highly dependent on the transportation costs of water and on the water quality. Because of the additional modifications and the water supply required for water injection, workshop participants indicated that operators prefer using low-NOx combustors for meeting RACT and BARCT requirements.

C. Severe Steam Injection

Wheelabrator submitted a capital cost estimate to the SCAQMD for severe steam injection of \$1.2 million to retrofit an LM2500 gas turbine located at the Metropolitan State Hospital in Norwalk (Wheelabrator, 1988). This is equivalent to a cost-effectiveness of \$5,000/ton from an initial level of 42 ppm controlled to 15 ppm. The cost-effectiveness for an LM5000, which is a much larger turbine, should be lower.

As noted earlier, severe steam injection could increase emissions of CO and THC. Therefore, an oxidation catalyst may be needed. Capital costs for installed oxidation catalysts range from \$280,000 to \$520,000 for an LM2500 and \$500,000 to \$670,000 for an LM5000. The cost-effectiveness for reducing CO from 170 ppm to 50 ppm is about \$400/ton for the LM2500 and \$200/ton for the LM5000. Cost and design data are presented in Tables 4 and 5.

Table 4

Design and Cost Information for Oxidation Catalysts Used on Gas Turbines With Severe Steam Injection[a]

Case 1: GE LM2500 - 22 MW
Exhaust Gas Conditions: 964° F 157 lb/sec

Catalyst Size and Cost

% Control	Size	Cost
70	11'x12'x3.7"	$113,575
80	12'x12'x3.7"	$123,900
90	15'x16'x3.7"	$206,500

Case 2: GE LM5000 - 33 MW

Exhaust Gas Conditions: 834° F 279 lbs/1sec

Catalyst Size and Cost

% Control	Size	Cost
70	15'x15.5'x3.7"	$200,275
80	16'x16.5'x3.7"	$227,410
90	17.25'x18'x3.7"	$267,500

Installation costs for a new installation would be about equal to the cost of the system. Retrofit costs would be higher.

Operating Costs
- Catalyst Replacement, 90% of system cost, every 3 years
- Fuel Penalty from pressure losses
  - 90% control 1.75" loss
  - 80% control 2.5" loss
  - 70% control 3" loss
- Annual steam cleaning-8 hours

[a] Harold Harris, Houston Silencing, June 25, 1991.

Table 5

Basis of Cost Effectiveness Calculation for CO Catalyst

General Assumptions
- Uncontrolled CO emissions - 170 ppm
- Controlled CO emissions - 50 ppm
- Installation costs - 2 times the equipment cost
- CRF - 10%, 15 years
- Labor - 40 hours/year, $40/hour
- 1/2% fuel penalty

LM5000 Additional Assumptions
- Exhaust gas temperature - 834° F
- Exhaust gas flowrate - 279 lbs/sec
- Density of exhaust gas - 0.03 lbs/cubic ft

LM2500 Additional Assumptions
- Exhaust gas temperature - 964° F
- Exhaust gas flowrate - 157 lb/sec
- Density of exhaust gas - 0.027 lb/cubic ft

D. Selective Catalytic Reduction

Cost-effectiveness data for SCR control systems are provided in the SCAQMD staff report. For a retrofit of water injection and SCR to achieve a limit of 9 ppm, the cost-effectiveness ranged from $1,800-$2,500/ton (1986$) for units 10 MW and over, and operating full time. The cost-effectiveness for units already equipped with water injection ranged from $3,000-$5,000/ton (1986$).

ARB staff conducted an independent cost analysis for several different sized turbines.based upon the installation of a high temperature (750-960° F) SCR catalyst with air dilution. The basis of the cost analysis is summarized in Table 6. Detailed cost information supporting the following analysis is contained in Appendix C.

The cost-effectiveness was calculated for two different types of applications: (1) gas turbines with a heat recovery boiler such as cogeneration and combined cycle applications (Figures 1-5); and (2) gas turbines without a heat recovery boiler such as utility and industrial peaker applications (Figures 6-9).

Figures 1 and 2 show the cost-effectiveness trends for retrofitting SCR to a level of 9 ppm with and without water injection, respectively. Figures 1 and 2 clearly show that for units 10 MW and over that are initially uncontrolled, NOx control to a 9 ppm limit is cost-effective down to a 0.1 capacity factor. For turbines in the 4.5-10 MW range, the cost-effectiveness is higher and exceeds $15,000/ton at relatively high capacity factors. For example, the cost-effectiveness for the 4.5 MW turbine for SCR

Table 6

Basis of SCR Cost Estimate

Catalyst System Cost (CSC)[a]
- Catalyst system
- Transition ducts
- Ammonia system
- Cooling air injection system
- Engineering specifications
- Performance data
- CEM - $100,000

Installation
- 80% of CSC for 4 and 10 MW units (cogeneration application)
- 60% of CSC for other units (cogeneration application)
- 40% of CSC for peakers

Capital Recovery Factor--10%, 15 yrs

Operating Costs[b]

Catalyst:	$400/cu ft
Ammonia:	$0.18/lb
Fuel Penalty Cost:	$3.69/MMBtu
Blower:	10% of fuel penalty cost
CEM Maintenance:	$30,000
Operator (including overhead):	$40/hr
Catalyst life:	3 yrs
Taxes and Insurance:	2% of capital costs

Emission Reductions
- Case 1: inlet-42 ppm
- Case 2: inlet-uncontrolled

Water Injection Costs
- $1500/ton for plant factor >.5
- $2000/ton for plant factor >.3
- $3000/ton for remaining units

[a] Cost based on Norton catalyst, (1991$).

[b] Efficiency loss in the HRSG was not accounted for. This is expected to be small because the turbine exhaust gas temperature is just slightly cooled and because the cooling is partially offset by the increase in exhaust gas mass.

Cost-Effectiveness of SCR for Gas Turbines with Heat Recovery Boilers

Figure 1: Uncontrolled to 9 ppm -- SCR only

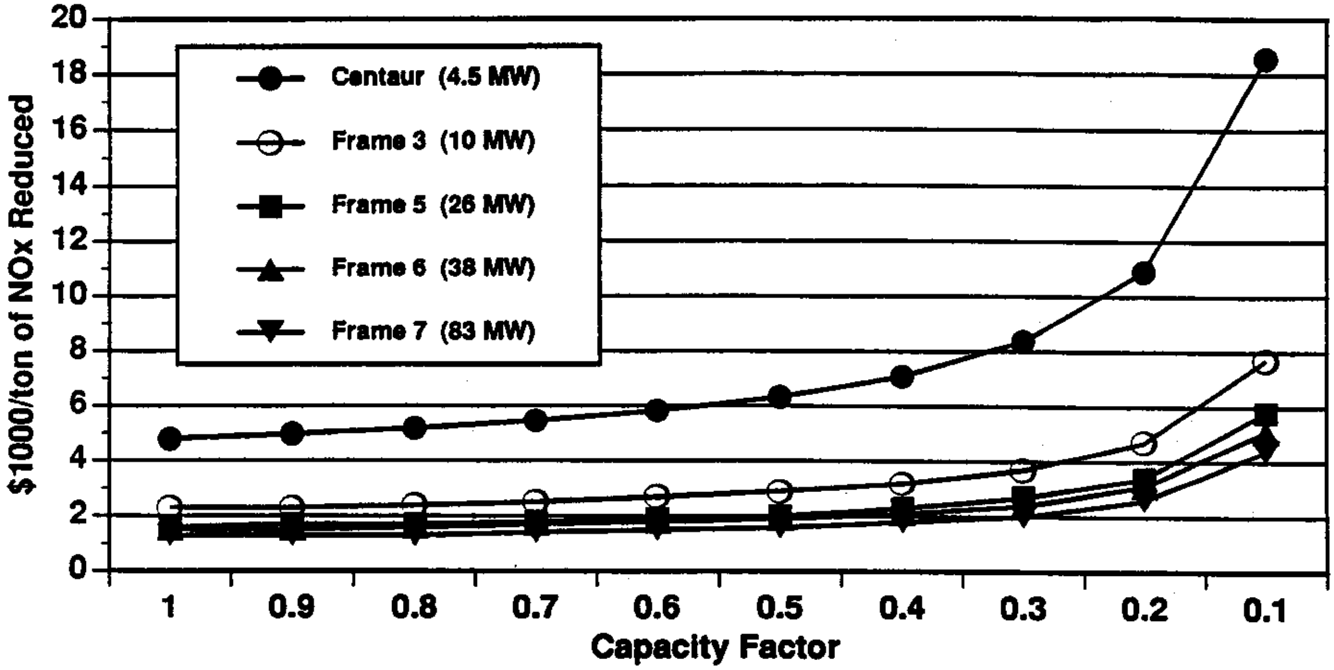
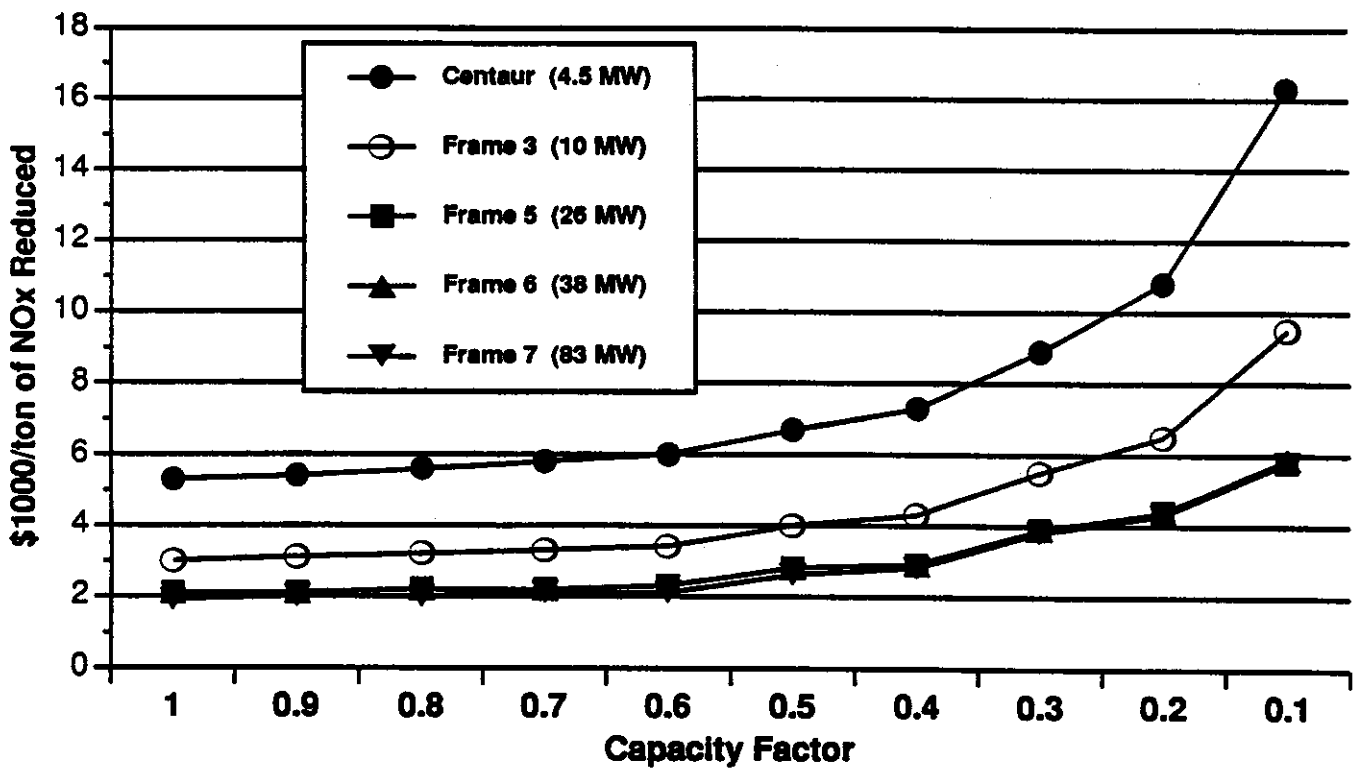


Figure 2: Water Injection to 42 and SCR to 9 ppm



only exceeds $15,000/ton at a capacity factor of 0.2. The trends also show that the cost-effectiveness for the SCR only case is slightly lower than the cost-effectiveness for the SCR and water injection case for similarly sized turbines.

Figure 3 shows the cost-effectiveness trends for retrofitting turbines from a controlled level of 42 ppm to 9 ppm. This is an important scenario because many turbines already have water injection. For this case, units over 20 MW reached a cost-effectiveness of $15,000/ton at a 0.1 capacity factor. Units in the 10 MW range reached a cost-effectiveness of $15,000/ton at a 0.2 capacity factor. Units under 10 MW reach the $15,000-$20,000/ton range at higher capacity factors (0.7 for a 4.5 MW turbine; 0.4 MW for a 10 MW turbine.

Figures 4 and 5 pertain to the 4.5 MW Centaur turbine. Figure 4 is a comparison of various control levels. Units that are initially uncontrolled fall into the cost-effective range. Units that are already controlled with water injection may or may not fall into the cost-effective range, depending upon the control level. Figure 5 compares the installed capital costs of water injection and SCR. The cost of SCR ranges from 30 to 60 percent of the cost of the gas turbine.

Figures 6 and 7 show the cost-effectiveness trends for various sizes of peaker units. Since peaker gas turbines do not have an associated heat recovery boiler, retrofit costs are lower. Figure 6, which describes the case of controlling and uncontrolled turbine to 9 ppm, shows that for units 10 MW and over the cost-effectiveness is less than $8,000/ton down to a 0.1 capacity factor. For units under 10 MW, the cost-effectiveness is about $10,000/ton at a 0.2 capacity factor and $16,000/ton at a 0.1 capacity factor.

Figure 7 describes the case for controlling NOx from 42 ppm to 9 ppm The trends for the case are similar to the case with the heat recovery boiler, shown in Figure 3.

Figures 8 and 9 pertain to the Centaur peaker. Figure 8 is a comparison of the various control levels. The same conclusions are drawn here as in the case with the heat recovery boiler, shown in Figure 4. Figure 9 compares the installed capital costs of water injection and SCR. The cost of SCR ranges from 25-45% of the cost of the gas turbine.

E. Methanol

The costs of retrofitting to methanol, based on the University of California, Davis (UCD) demonstration of an Allison 501-KB (3 MW), were estimated to range from $420,300 to $768,700 (1984$). Costs for larger gas turbines could be estimated based on the "six-tenths factor" (Peter, 1980). The operating labor, maintenance labor, and maintenance material cost should be similar to those of a conventional-fueled gas turbine. The overriding impact upon the operating costs of a methanol-fueled gas turbine would be the cost of the fuel itself which is about 2 - 3 times as costly as natural gas.

Figure 3: Cost-Effectiveness of SCR for Gas Turbines with Heat Recovery Boilers

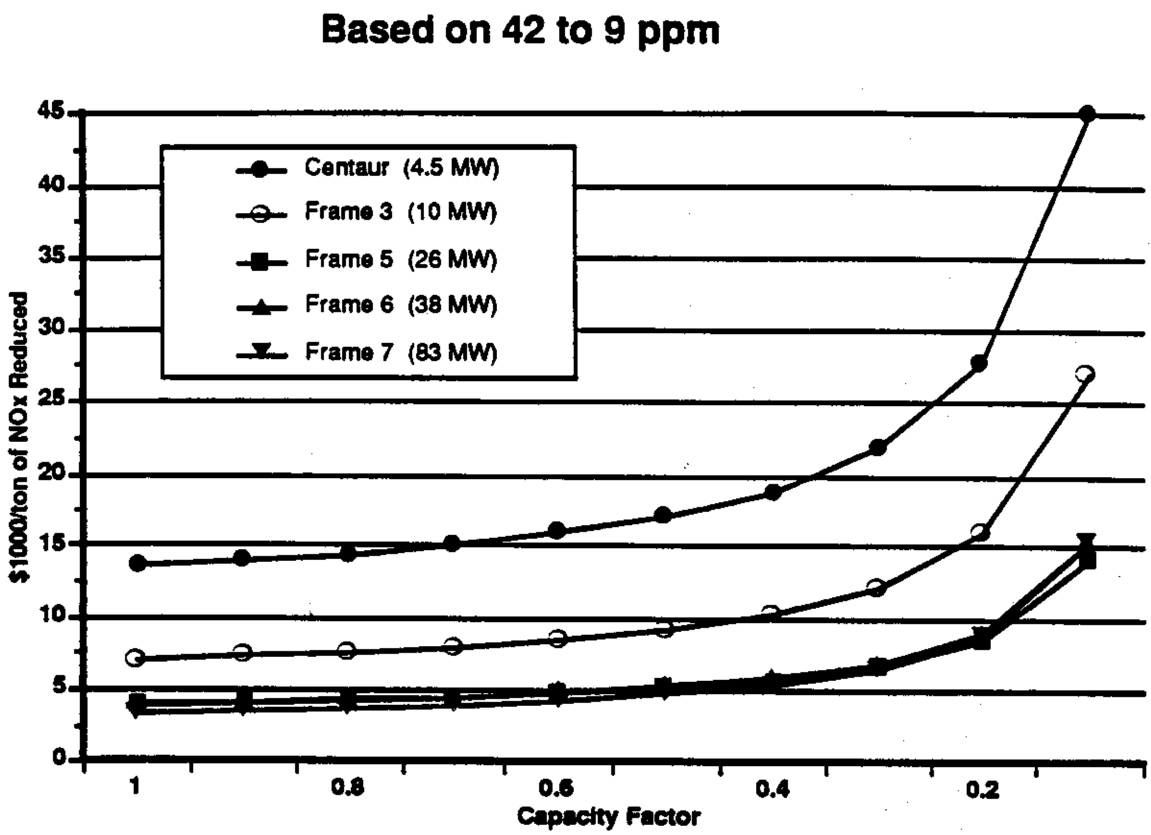


Figure 4: Cost Effectiveness of SCR for Centaur

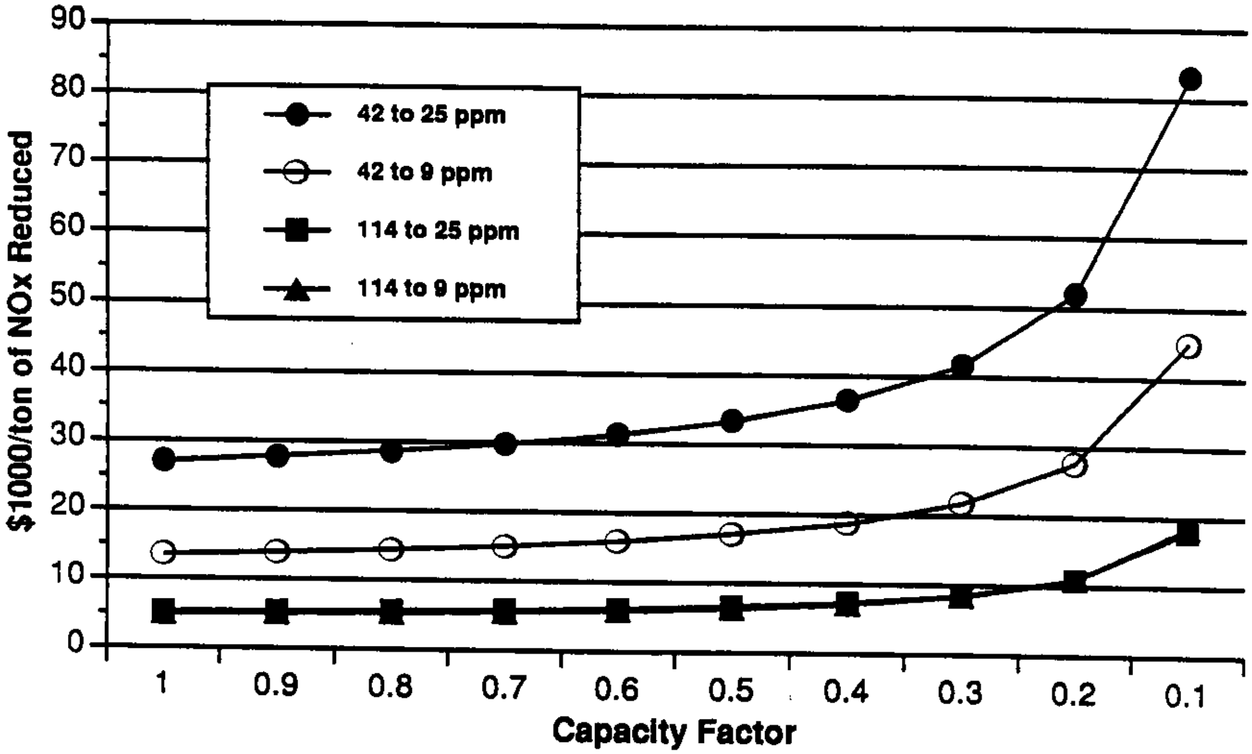
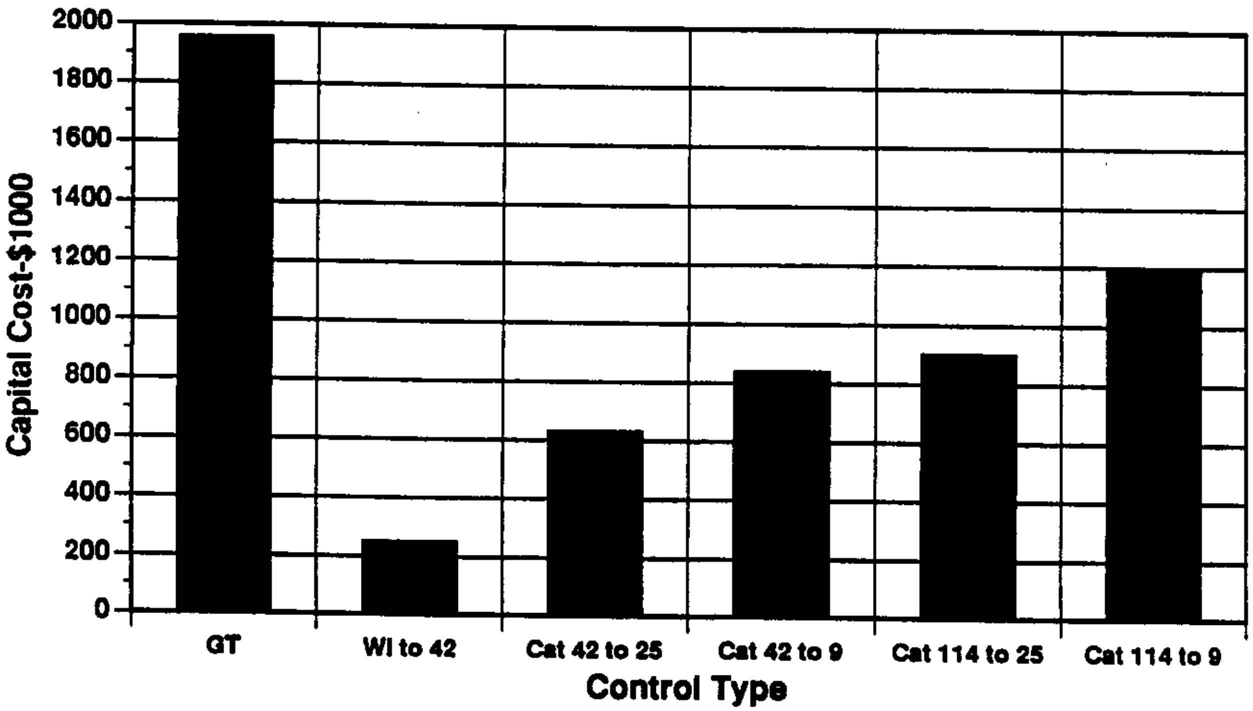


Figure 5: Capital Cost of Control Equipment For Centaur



Cost Effectiveness of SCR for Peakers

Figure 6: Uncontrolled to 9 ppm -- SCR only

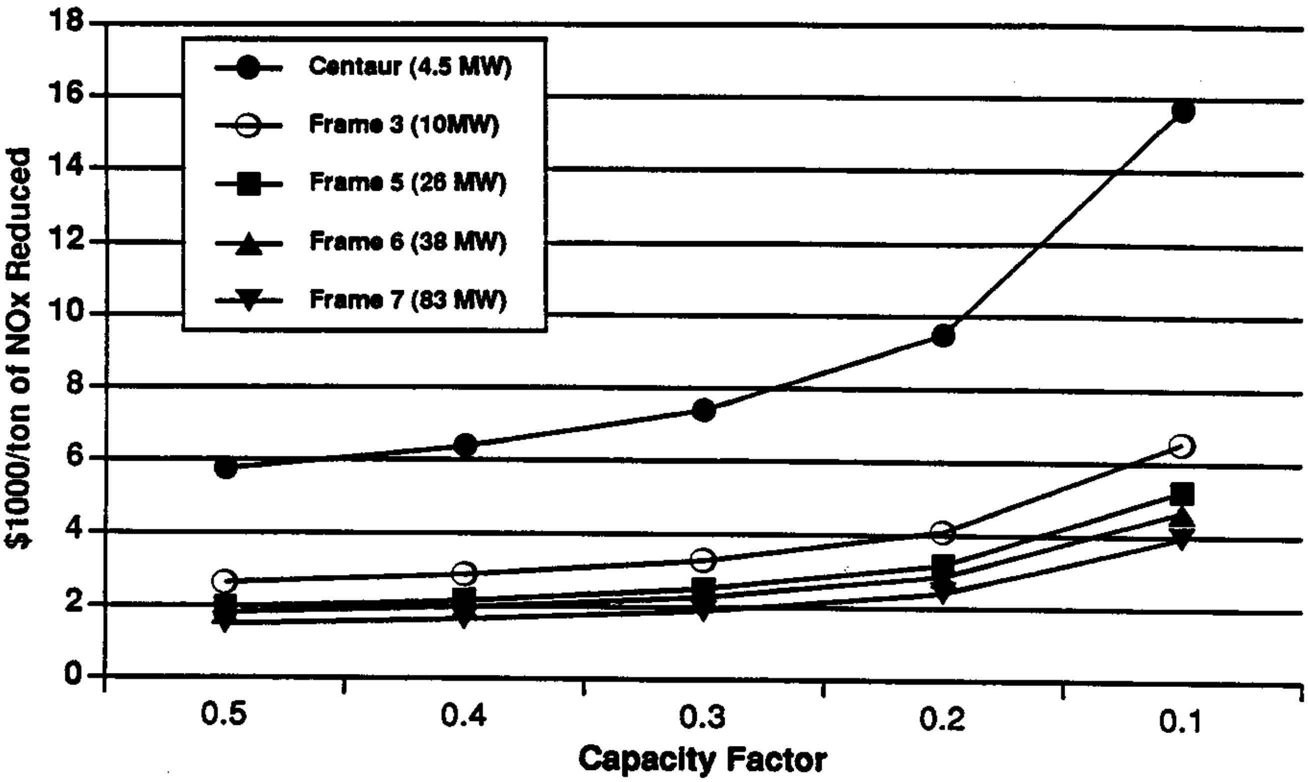


Figure 7: 42 to 9 pm - SCR

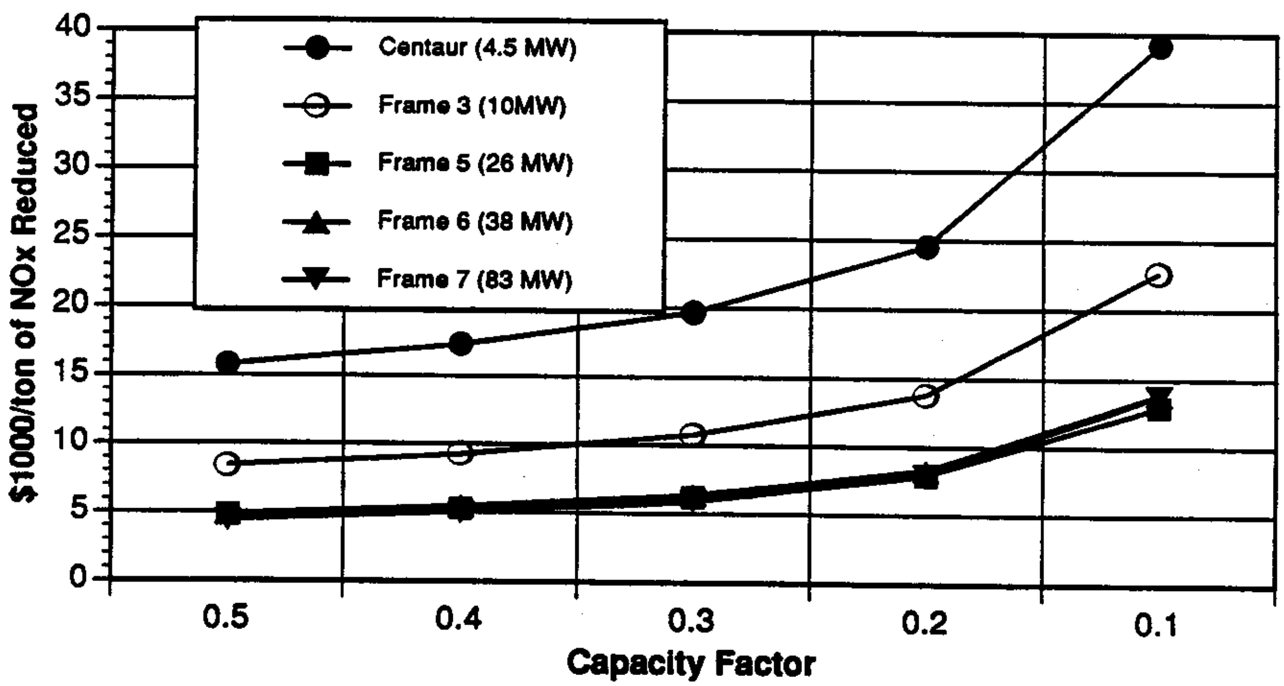


Figure 8: Cost-Effectiveness of SCR for Centaur Peaker

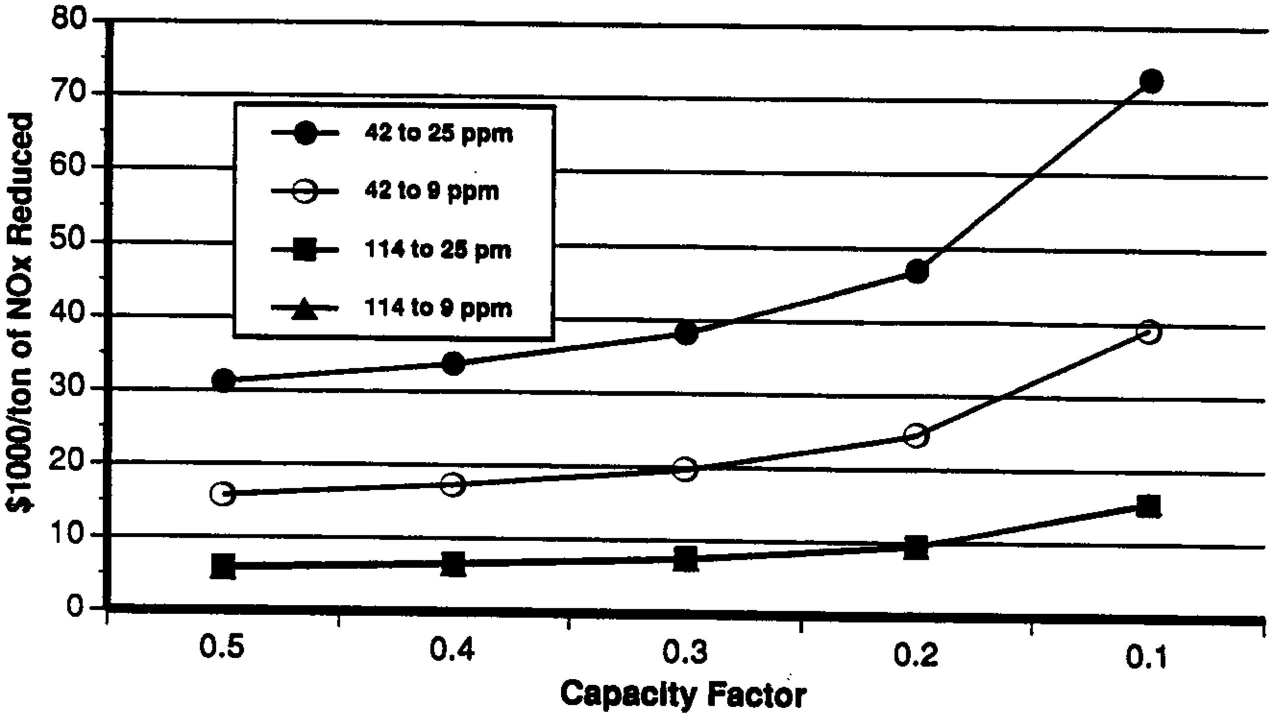
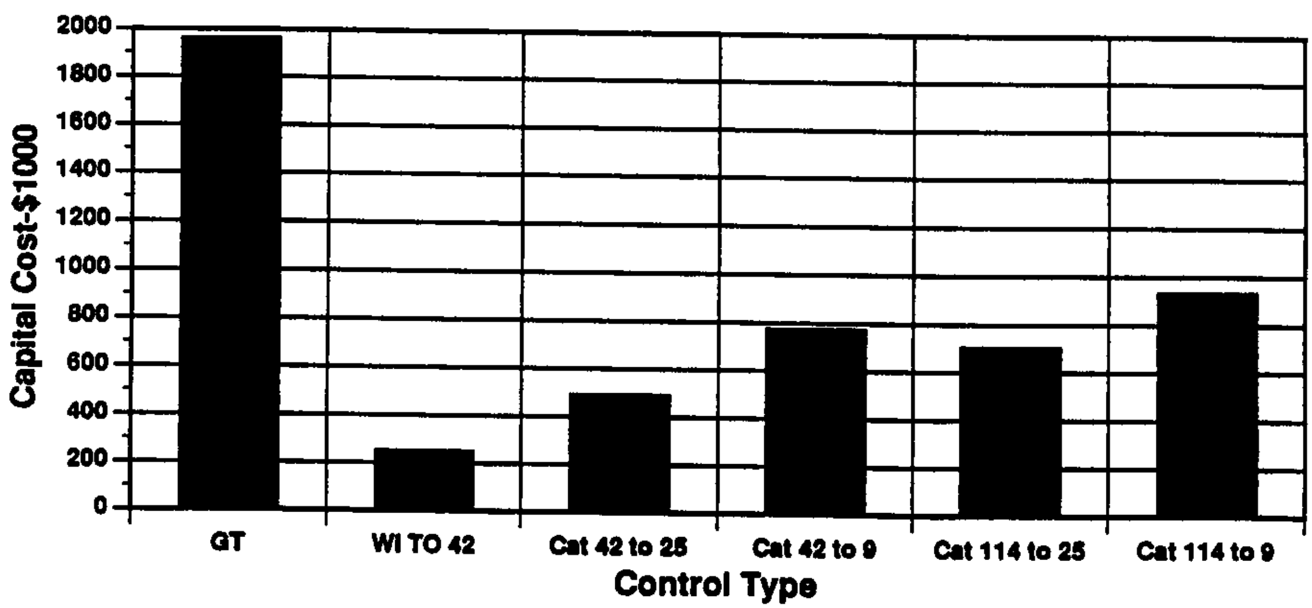


Figure 9: Capital Cost of Control Equipment for Centaur Peaker



GT= Gas turbine WI= Water injection
Cat= Catalyst control to specified pppm level

The cost-effectiveness for the UCD installation was over $20,000/ton. At that time, methanol was only 2 times more expensive than natural gas. Today methanol is 2.5-3 times more expensive than natural gas (Koski, 1990). Thus the cost-effectiveness would be well over $20,000/ton. Since the fuel cost is the overriding factor, larger installations would not be much more cost-effective. The SCAQMD staff report suggested that methanol firing would be a viable alternative for gas turbines used less than 1000 hours/year.

IV. IMPACTS

Compliance with the proposed standards is expected to have an environmental impact. The SCAQMD Revised Draft EIR identified the following impacts: economics, air quality, effects of SCR and methanol usage, and energy consumption. In addition, the ARB staff report for the gas turbine SCM also identified water usage. All the above issues except for energy consumption and water usage were identified in the SCAQMD Revised Draft EIR to be insignificant or mitigable to nonsignificance.

A. Economic

The proposed regulations would impose costs on turbine owners for which they will receive no corresponding revenue. Owners may experience any combination of the following costs: downtime for retrofit, retrofit, higher costs of methanol fuel, increased maintenance costs, and increased water consumption. These costs could result in increased energy prices. Sectors which would experience an economic stimulus include pollution control manufacturers, engineering firms, and plumbing, electrical, and other contractors.

B. Air Quality

Imposing NOx controls would reduce NO_2 levels, PM_{10} emissions, and acid deposition. Visibility should improve. The reduction of oxides of nitrogen should also result in a decrease in ozone levels, depending upon a number of parameters including the NOx/HC ratio. Carbon monoxide emissions can increase from the use of water/steam injection or from the use of methanol. Mitigation measures include modifications to the combustion parameters (oxygen, temperature, time), equipment (fuel nozzles, combustion chamber), and the addition of post combustion controls. Also, the use of methanol may result in formaldehyde emissions. However, by following proper operating procedures, formaldehyde emissions can be maintained below levels that present an acceptable risk.

C. Selective Catalytic Reduction

The use of SCR will result in free ammonia, PM_{10}, and SO_3 emissions. Ammonia emissions at high concentrations can create an odor nuisance. However, the impact can be mitigated by proper stack design. Free ammonia emissions in the exhaust can form PM_{10} constituents such as ammonium sulfate or ammonium nitrate aerosols. Most areas in California are in violation of the state and federal ambient PM_{10} standard. The risk of ammonia slip could be partially mitigated (to at least below 20 ppm) by specifying ammonia discharge limits on the operating permits and by carefully controlling ammonia injection with monitoring equipment. However, this determination has no requirement for ammonia monitors or ammonia slip limits. These decisions are best made by the local districts. Nevertheless, because ammonia slip cannot be completely mitigated, the risk of ammonia emissions must be weighed against the benefits of NOx reduction.

Ammonia is a hazardous (flammable) and toxic compound and its production, use, storage, and transport can be hazardous, especially in the case of worker contact with liquid ammonia or exposure to highly concentrated ammonia vapor. The risk of accidental ammonia releases and associated health impacts can be reduced significantly by proper design practices, alarm systems, safety programs, worker training programs. Such programs have been developed by the chemical industry and are set forth in various publications. SCR related ammonia storage and handling will also create a potential increase in work place hazards from possible feedline ruptures during earthquakes.

Also, there is speculation that conditions in the SCR system may encourage the conversion of ammonia into nitrosamines, which are toxic, carcinogenic, and mutagenic. However, two independent source tests for nitrosamines have been conducted on the flue gas of units equipped with SCR. Neither source test detected the presence of nitrosamines.

Ammonia emissions at high enough concentrations can also create an odor nuisance if there is not adequate stack dispersion. Nuisance impacts can be completely mitigated by proper stack design.

The amount of SO_3 emissions can be minimized by using low sulfur fuel. It should be noted that total SOx emissions are not increased. The amount of directly emitted SO_3 is increased as a ratio of total SOx emitted and correspondingly a reduction in SO_2 emissions occurs.

SCR catalyst materials may contain small amounts of hazardous materials, including vanadium pentoxide. This compound is toxic if inhaled. Also, spent catalyst material must be safely disposed of. The first issue, particle inhalation from catalyst erosion, can be minimized by modifying the catalyst chamber to protect the catalyst from direct exposure to exhaust particulates. The second issue, catalyst disposal, is minimal because the spent catalyst is returned to the catalyst vendors for proper disposal or recycling of the catalyst.

D. Methanol

Methanol is a toxic as well as flammable substance. Methanol would be transported by tank trucks or rail tank cars. There are potential environmental and public health impacts from accidental spills during transport. The risk of upset can be mitigated by following published guidelines on safety, handling, and transportation.

E. Water Usage

Both steam and water injection require the use of water. Satisfying the water demand may burden the water supply system.

F. Energy Impacts

The use of NOx reduction technologies would generally have some level of fuel energy penalty or may require small amounts of energy for their operation. For example, the conversion of natural gas to methanol or ammonia requires natural gas for feedstock and fuel. The diversion of natural gas to make methanol and ammonia could impact the availability of natural gas for utility fuel. For methanol, however, the energy loss is partially offset by an improvement of turbine efficiency. An example of operational energy is the energy required to operate the SCR system. The use of SCR results in a 0.7 percent fuel penalty.

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APPENDIX A

RACT and BARCT Determination

DETERMINATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY AND BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY FOR THE CONTROL OF OXIDES OF NITROGEN FROM STATIONARY GAS TURBINES[a/]

I. Applicability

Except as provided in Section IV., this determination shall apply to all stationary gas turbines, 0.3 megawatt (MW) and larger.

II. Definitions

A. **Compliance Limit** means allowable NOx emissions (ppm by volume).

B. **Control System Operating Parameters** means operating parameters that the Air Pollution Control Officer deems necessary to analyze when determining compliance, such as ammonia and exhaust gas flow rates and exhaust gas temperature for SCR; or humidity, water injection rate, exhaust gas flow rate and temperature for water injection.

C. **Emergency Standby Unit** means a stationary gas turbine that operates only as a mechanical or electrical power source for a facility when the primary power source has been rendered inoperable due to failure beyond the reasonable control of the operator, except due to power interruption pursuant to a voluntary interruptable power supply agreement. Electricity generated by such unit cannot be sold.

D. **HHV** means the higher heating value of fuel.

E. **LHV** means the lower heating value of fuel.

F. **Measured NOx Emissions Concentration** is the concentration corrected to International Standards Organization (ISO) standard conditions:

$$NOx = (NOx\ obs)(Pref/Pobs)^{0.5}(288K/Tamb)^{1.53}(e^{19(Hobs-0.00633)})$$

Where:

NOx = emissions of NOx at 15 percent oxygen and ISO standard conditions on a dry basis, ppm.
NOx obs = measured NOx emissions corrected to 15 percent oxygen on a dry basis, ppm.
Pref = standard reference pressure, (14.696 psia).
Pobs = measured site ambient absolute pressure, psia.
Hobs = measured humidity of ambient air, pounds water per pound dry air.

a/ Please note that this determination is structured to apply to either RACT or BARCT. Those sections which apply only to BARCT are noted in the determination.

e = transcendental constant (2.718).
Tamb = measured temperature of ambient air, degrees K.

or an alternate correlation that corrects to ISO standard conditions and is approved by the APCO.

G. **Pipeline Gas Turbines** means a stationary gas turbine used to transport gases or liquids in a pipeline.

H. **Power Augmentation** means an increase in the gas turbine shaft output and/or the decrease in gas turbine fuel consumption by the addition of energy recovered from exhaust heat.

I. **Public Service Unit** means a gas turbine used to generate electricity for sale or for use in serving the public.

J. **Rating** means the continuous megawatt (MW) rating or mechanical equivalent by a manufacturer for gas turbine(s) without power augmentation.

K. **Stationary Gas Turbine** or **Unit** means any gas turbine system that is gas and/or liquid fueled with or without power augmentation. This unit is either attached to a foundation at a facility or is portable equipment operated at a specific facility for more than 90 days in any 12-month period. Two or more gas turbines powering one shaft shall be treated as one unit.

L. **Thermal Stabilization Period** means the start up time necessary to bring the heat recovery steam generator to the proper temperature, not to exceed two hours.

III. Standards

The owner or operator of any stationary gas turbine unit shall not operate such unit under load conditions, excluding the thermal stabilization period, which results in the measured NOx emissions concentration exceeding the compliance limit listed below averaged over 15 minutes.

(For RACT)

Unit Size Megawatt Rating (MW)	Compliance Limit NOx, ppm at 15% O2	
	Gas[a]	Oil[b]
0.3 MW and Greater	42	65

[a] Gas includes natural, digester and landfill.
[b] Oil includes kerosene, jet fuel, and distillate. The sulfur content of the oil shall be less then 0.05%.

(For BARCT)

Unit Size Megawatt Rating (MW)	Compliance Limit NOx, ppm at 15% O2 Gas[a]	Oil[b]
0.3 to Less Than 2.9 MW and Units Greater Than or Equal to 4 MW, Operating Less Than 877 Hours/Yr.	42	65
2.9 to Less Than 10 MW	$25 \times \frac{EFF}{25}$	65
10.0 MW and Over With SCR	$9 \times \frac{EFF}{25}$	$25 \times \frac{EFF}{25}$
10.0 MW and Over Without SCR	$15 \times \frac{EFF}{25}$	$42 \times \frac{EFF}{25}$

[a] Gas includes natural, digester, and landfill.
[b] Oil includes kerosene, jet, and distillate. The sulfur content of the oil shall be less than 0.05%.

Where:

EFF (efficiency) is the higher of (1) or (2). An EFF that is less than 25 percent shall be assigned a value of 25 percent.

(1) $$EFF = \frac{3412 \times 100\%}{\text{Actual Heat Rate at HHV of Fuel (BTU/KW-HR)}}$$

which is the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any downstream energy recovery from the actual heat rate, (BTU/KW-HR) or 1.34 (BTU/HP-HR); corrected to the HHV (higher heating value) of the fuel and ISO conditions, as measured at peak load for that facility.

or

(2) $$EFF = (\text{Manufacturer's Rated Efficiency with Air Pollution Equipment at LHV}) \times \frac{LHV}{HHV}$$

which is the manufacturer's continuous rated percent efficiency of the gas turbine with air pollution equipment after correction from LHV to HHV of the fuel at peak load for that facility.

IV. Exemptions

A. The provisions of this rule, with the exception of Section VII. A.(3), shall not apply to the operation of gas turbines used under the following conditions:

(1) Laboratory units used in research and testing for the advancement of gas turbine technology,

(2) Units operated exclusively for firefighting and/or flood control,

(3) Pipeline gas turbines provided that the owner/operator demonstrates to the satisfaction of the APCO that water or steam injection, selective catalytic reduction, or any other emission control technology is not technologically feasible, cost effective or creates adverse environmental impacts such as those associated with the use, transport, or disposal of supplies such as water and ammonia, and

(4) [reserved for specific exemptions determined by the APCO to be technologically infeasible or not cost-effective to retrofit]

B. The provisions of this rule with the exception of Section VII. A.(3), B.(6), and C. shall not apply to the operation of gas turbines used under the following conditions:

(1) Emergency standby units demonstrated to operate less than 200 hours per calendar year,

(2) Units less than 4 MW operating less than 877 hours per year,

V. Compliance Schedule

Owners or operators of all applicable gas turbine units shall comply with the applicable provisions of Section III. in accordance with the following schedule:

A. By _____ (2 years after adoption date), submit to the Executive Officer for approval an emission control plan of actions which will be taken to demonstrate compliance.

B. By _____ (4 years after district rule adoption date), demonstrate final compliance.

VI. Test Methods

Oxides of nitrogen emissions for compliance source tests shall be determined by using ARB Method 20. Oxygen content of the exhaust gas shall be determined by using ARB Method 422, Determination of Volatile Organic Compound Emissions from Stationary Sources. The HHV and LHV shall be determined using ASTM D240-87, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, or ASTM D2382-88, Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-precision Method), for distillate fuel, and ASTM D3588-91, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels, ASTM D1826-88, Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter or ASTM D1945-81, Standard Method for Analysis of Natural Gas by Gas Chromatography, for gaseous fuels.

VII. Administrative

A. Emission Control Plan

The owner or operator of any existing stationary gas turbine shall submit to the Air Pollution Control Officer for approval an Emissions Control Plan of all actions, including a schedule of increments of progress, which will be taken to meet or exceed requirements of the applicable emissions limitations in Section III. and compliance schedule in Section V.

(1) Such plan shall contain at a minimum a list that provides the following for each gas turbine:

(a) Permit or identification number,
(b) Name of gas turbine manufacturer,
(c) Model designation,
(d) Rated shaft power output (MW),
(e) Type of liquid fuel and/or type of gaseous fuel,
(f) Fuel consumption (cubic feet of gas or gallons of liquid) for the previous one-year period,
(g) Hours of operation in the previous one-year period.
(h) Heat rate (BTU/KW-HR), corrected to the HHV for each type of fueling (liquid/gas),
(i) HHV for each fuel,

(2) A list of all gas turbines required to be controlled, identifying the type of emission control to be applied to each gas turbine along with documentation showing existing emissions of oxides of nitrogen.

(3) Support documentation for any units exempt under the provisions of Section IV.

B. Monitoring and Recordkeeping Requirements

The owner or operator of any stationary gas turbine subject to the provisions of this rule shall perform the following actions:

(1) Install, operate, and maintain in calibration, equipment, as approved by the Air Pollution Control Officer, that continuously measures and records the following:

(a) Control System Operating Parameters,

(b) Elapsed time of operation, and

(FOR BARCT)

(c) For units 10 MW and over that operated an average of more than 4000 hours per year over the last three years before ______ (date of adoption), the exhaust gas NOx concentrations corrected to ISO conditions at 15 percent oxygen on a dry basis. The NOx monitoring system shall meet EPA requirements as specified in 40 CFR Part 60 App. B, Spec. 2 or other systems that are acceptable to the EPA.

(2) All records shall be available for inspection at anytime for a period of two years.

(3) Submit to the Air Pollution Control Officer information demonstrating that the system has data gathering and retrieval capability.

(4) Submit to the Air Pollution Control Officer before issuance of the Permit to Operate information correlating the Control System Operating Parameters to the associated measured NOx output. This information may be used by the Air Pollution Control Officer to determine compliance when there is no continuous emission monitoring system for NOx available or when the continuous emission monitoring system is not operating properly.

(5) Provide source test information ______ (annually) regarding the exhaust gas NOx concentration at ISO conditions corrected to 15 percent oxygen on a dry basis, and the percent efficiency (EFF) of the turbine unit.

(6) Maintain a gas turbine operating log that includes, on a daily basis, the actual Pacific Standard Time start-up and stop time, total hours of operation, type and quantity of fuel used (liquid/gas). This information shall be available for inspection at any time for two years from the date of entry.

(7) Maintain a gas turbine operating log for units exempt under Section IV.B. that includes, on a daily basis, the actual

Pacific Standard Time start-up and stop time, total hours of operation, and cumulative hours of operation to date for the calendar year. This information shall be available for inspection at any time for two years from the date of entry and submitted to the Air Pollution Control Officer at the end of each calendar year in a manner and form approved by the Air Pollution Control Officer.

C. Exempt Units and Emergency Standby Units

Exempt units and emergency standby units must comply with the following:

(1) The owner or operator of any unit listed below must notify the Air Pollution Control Officer within seven days if the hour-per-year limit is exceeded. A public service unit operating during a state of emergency, when such emergency is declared by proclamation of the Governor and when the unit is located in the specific geographic location identified in the proclamation, shall be excluded from the hour-per-year limit. If the hour-per-year limit is exceeded, the exemption shall be permanently withdrawn. Within 30 days after the exceedance, the owner or operator must submit a permit application detailing a plan to meet the applicable RACT or BARCT limits within 24 months. Included with this permit application, the owner or operator must submit an emission control plan including a schedule of increments of progress for the installation of the required control equipment. This schedule shall be subject to the review and approval of the Air Pollution Control Officer.

(a) Any unit smaller than 4 MW or emergency standby unit exempt under Section IV B.

(For BARCT)

(b) Any unit equal to or greater than 4 MW

APPENDIX B

Summary of Rules Reviewed

Summary of Rules Reviewed

San Diego County APCD
Rule 68: Fuel - Burning Equipment - Oxides of Nitrogen

South Coast Air Quality Management District
Rule 1134: Emissions of Oxides of Nitrogen from Stationary Gas Turbines
Rule 474: Fuel Burning Equipment - Oxides of Nitrogen

San Bernardino County APCD
Rule 474: Fuel Burning Equipment - Oxides of Nitrogen
Rule 475: Electric Power Generating Equipment

Great Basin Valley
Rule 404-B: Oxides of Nitrogen

Air Resources Board
Suggested Control Measure to Limit NOx Emissions from Electric Utility Gas Turbines

Most of the rules listed are aimed at boilers. Accordingly, for these rules the heat rates are reported in terms of MMBTU/hr gross heat input and the emission requirements are reported in ppm at 3% O_2. Heat rates and emission requirements for gas turbines are generally reported in terms of MW output and ppm at 15% O_2. In the following rule summaries heat rates and emission limits in parentheses are in terms of MW output at 25% efficiency and ppm at 15% O_2. These values were calculated from those specified in the rules.

San Diego County

Rule 68: Fuel-Burning Equipment - Oxides of Nitrogen

Applicability

$\geq$ 50 MMBTU/hr (3.7 MW)

Requirements/Standards

	gas	liquid
ppm @ 3% O_2	125	225
ppm @ 15% O_2	(42)	(75)

Exemptions

Test equipment for turbine engines or components

Turbine engines during a continuous thirty minute period for start up, a continuous thirty minute period for shut down and a continous thirty minute period during fuel switching.

South Coast

Rule 1134: Emissions of Oxides of Nitrogen from Stationary Gas Turbines

Applicability

≥.3 MW

Requirements/Standards*

Size-MW	ppm @ 15% O_2
≥ .03 and <2.9	25
≥ 2.9 and <10	9
≥ 2.9 and <10 No SCR	15
≥ 10	9
≥ 10 No SCR	12
≥ 60 Combined cycle	9
≥ 60 Combined cycle No SCR	15

* Based on 25% efficiency. Emission limits are adjusted for efficiency. Efficiency is based on power turbine output divided by higher heating value of fuel.

Exemptions

Laboratory units
Firefighting and/or flood control
Chemical gas processing units
Emergency standby operating less than 200 hours per calendar year
Peaking units operating less than 200 hours per calendar year

Administrative Requirements

Compliance Schedule

	Control Plan	Final Compliance
.3 to 10 MW	12/31/93	12/31/95
10 MW and over	12/31/92	12/31/95
60 MW and over Combined cycle	12/31/92	12/31/95
Demonstration Turbines		
GE LM-5000	12/31/89	12/31/90
GE LM-2500	12/31/89	12/31/91

Recordkeeping/Monitoring

Requires continuous monitoring of flow rate of liquids or gases and the ratio of water or steam to fuel added, and the maintenance of an operating log.

Requires continuous in-stack NOx monitoring system for cogeneration and combined cycle.

<u>Special Issues</u>

The rule provides for a demonstration program for units 10 MW and over. A GE LM-5000 and a LM-2500 are to be tested for compliance with the 12 ppm reference limit using steam injection. If either unit fails to pass the demonstration test within the specified time period, then the limit for all units in this category will be 9 ppm. Control plans must be submitted by 8/1/92, followed by compliance with the 9 ppm reference limit by 8/1/93. Any unit which complies with the less stringent limit by 2/1/92 shall not be affected by a failure of the demonstration program.

Rule 474: Fuel Burning Equipment - Oxides of Nitrogen

<u>Applicability</u>

≥ 555 MMBTU/hr (40.6 MW)

<u>Requirements/Standards</u>

≥555 and <1786 MMBTU/hr

	gas	liquid
ppm @ 3% O_2	300	400
ppm @ 15% O_2	(100)	(133)

≥1786 and <2143 MMBTU/hr

ppm @ 3% O_2	225	325
ppm @ 15% O_2	(75)	(108)

≥2143 MMBTU/hr

ppm @ 3% O_2	125	225
ppm @ 15% O_2	(42)	(75)

San Bernardino County

Rule 474: Fuel Burning Equipment - Oxides of Nitrogen

<u>Applicability</u>

>555 MMBTU/hr (40.6 MW)

<u>Requirements/Standards</u>

	gas	liquid
ppm @ 3% O_2	125	225
ppm @ 15% O_2	(42)	(75)

When more than one type of fuel is used, the allowable concentration shall be determined by proportioning the gross heat for each fuel.

Rule 475: Electric Power Generating Equipment

Applicability

>50 MMBTU/hr (3.7 MW)

Requirements/Standards

	gas	liquid
ppm @ 3% O_2	80	160
ppm @ 15% O_2	(27)	(53)

Great Basin Valley

Rule 404-B: Oxides of Nitrogen

Applicability

≥ 1 1/2 billion BTU per hour (110 MW)

Requirements/Standards

	gas	liquid
ppm @ 3% O_2	125	225
ppm @ 15% O_2	(42)	(75)

Air Resources Board

Suggested Control Measure to Limit NOx Emissions from Electric Utility Gas Turbines

Applicability

Gas turbines are used for the production of electric power and are owned or operated by a private or public electric utility.

Requirements/Standards*

	Installed before 1/1/89	Installed on/after 1/1/89
Methanol or Natural Gas	25	12
Other	40	20

* Based on 25% efficiency. Emission limits are adjusted for efficiency. Efficiency is sum of total electrical and useful heat output divided by higher heating value of fuel.

Exemptions

Units operated less than 200 hours per calendar year

Special Issues

The limits were technology forcing. Industry was to participate in a demonstration program to determine the feasibility of meeting these limits. If these limits could not be achieved, industry could petition for a hearing to adjust the limits or dates.

APPENDIX C

Cost Tables for SCR

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	1.00		
CEM Maintenance	30,000.00	From Initially Uncontrolled to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	19,200.00	30,000.00	113,733.33	206,533.33	208,533.33	444,933.33
Ammonia	14,033.52	16,556.40	203,722.56	453,014.64	518,451.84	1,165,885.92
Fuel Penalty (.5%)	8,006.75	8,006.75	22,518.47	50,232.12	67,400.25	141,601.56
Blower (if needed)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Operator	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	424,807.95	438,911.94	727,074.75	1,103,078.35	1,189,471.42	2,162,968.84
Total Annual Costs	543,157.95	596,317.44	949,501.74	1,496,830.80	1,586,769.74	2,962,362.60
Emission Reductions-tpy	105.56	124.39	421.36	932.50	1,069.16	2,413.38
C/E-$/ton	5,145.59	4,793.86	2,253.44	1,605.18	1,484.13	1,227.47

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.90		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	17,280.00	27,000.00	102,360.00	185,880.00	187,680.00	400,440.00
Ammonia	12,630.17	14,900.76	183,350.30	407,713.18	466,606.66	1,049,297.33
Fuel Penalty (.5%)	7,206.08	7,206.08	20,266.62	45,208.91	60,660.23	127,441.40
Blower (if needed)	720.61	720.61	2,026.66	4,520.89	6,066.02	12,744.14
Operator	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	385,563.85	398,335.56	657,812.13	996,558.02	1,074,318.87	1,951,270.75
Total Annual Costs	503,913.85	555,741.06	880,239.12	1,390,310.47	1,471,617.19	2,750,664.51
Emission Reductions-tpy	95.00	111.95	379.22	839.25	962.24	2,172.04
C/E-$/ton	5,304.23	4,964.07	2,321.18	1,656.61	1,529.36	1,266.40

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.80		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	15,360.00	24,000.00	90,986.67	165,226.67	166,826.67	355,946.67
Ammonia	11,226.82	13,245.12	162,978.05	362,411.71	414,761.47	932,708.74
Fuel Penalty (.5%)	6,405.40	6,405.40	18,014.78	40,185.69	53,920.20	113,281.25
Blower (if needed)	640.54	640.54	1,801.48	4,018.57	5,392.02	11,328.12
Operator	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	346,319.76	357,759.17	588,549.51	890,037.69	959,166.33	1,739,572.65
Total Annual Costs	464,669.76	515,164.67	810,976.50	1,283,790.14	1,356,464.65	2,538,966.41
Emission Reductions-tpy	84.45	99.51	337.08	746.00	855.33	1,930.70
C/E-$/ton	5,502.54	5,176.83	2,405.85	1,720.89	1,585.90	1,315.05

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.70		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	13,440.00	21,000.00	79,613.33	144,573.33	145,973.33	311,453.33
Ammonia	9,823.46	11,589.48	142,605.79	317,110.25	362,916.29	816,120.14
Fuel Penalty (.5%)	5,604.73	5,604.73	15,762.93	35,162.48	47,180.18	99,121.09
Blower (if needed)	560.47	560.47	1,576.29	3,516.25	4,718.02	9,912.11
Operator	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	307,075.66	317,182.79	519,286.89	783,517.36	844,013.78	1,527,874.55
Total Annual Costs	425,425.66	474,588.29	741,713.88	1,177,269.81	1,241,312.10	2,327,268.31
Emission Reductions-tpy	73.89	87.07	294.95	652.75	748.41	1,689.37
C/E-$/ton	5,757.51	5,450.38	2,514.72	1,803.55	1,658.60	1,377.60

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.60		
CEM Maintenance	30,000.00	From Initially Uncontrolled to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	11,520.00	18,000.00	68,240.00	123,920.00	125,120.00	266,960.00
Ammonia	8,420.11	9,933.84	122,233.54	271,808.78	311,071.10	699,531.55
Fuel Penalty (.5%)	4,804.05	4,804.05	13,511.08	30,139.27	40,440.15	84,960.94
Blower (if needed)	480.41	480.41	1,351.11	3,013.93	4,044.02	8,496.09
Operator	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	267,831.57	276,606.41	450,024.27	676,997.03	728,861.24	1,316,176.46
Total Annual Costs	386,181.57	434,011.91	672,451.26	1,070,749.48	1,126,159.56	2,115,570.22
Emission Reductions-tpy	63.33	74.64	252.81	559.50	641.49	1,448.03
C/E-$/ton	6,097.46	5,815.11	2,659.87	1,913.76	1,755.52	1,461.00

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.50		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	9,600.00	15,000.00	56,866.67	103,266.67	104,266.67	222,466.67
Ammonia	7,016.76	8,278.20	101,861.28	226,507.32	259,225.92	582,942.96
Fuel Penalty (.5%)	4,003.38	4,003.38	11,259.24	25,116.06	33,700.13	70,800.78
Blower (if needed)	400.34	400.34	1,125.92	2,511.61	3,370.01	7,080.08
Operator	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	228,587.47	236,030.02	380,761.64	570,476.70	613,708.69	1,104,478.36
Total Annual Costs	346,937.47	393,435.52	603,188.63	964,229.15	1,011,007.01	1,903,872.12
Emission Reductions-tpy	52.78	62.20	210.68	466.25	534.58	1,206.69
C/E-$/ton	6,573.40	6,325.74	2,863.08	2,068.05	1,891.22	1,577.76

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.40		
CEM Maintenance	30,000.00	From Initially Uncontrolled to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	7,680.00	12,000.00	45,493.33	82,613.33	83,413.33	177,973.33
Ammonia	5,613.41	6,622.56	81,489.02	181,205.86	207,380.74	466,354.37
Fuel Penalty (.5%)	3,202.70	3,202.70	9,007.39	20,092.85	26,960.10	56,640.62
Blower (if needed)	320.27	320.27	900.74	2,009.28	2,696.01	5,664.06
Operator	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	189,343.38	195,453.64	311,499.02	463,956.37	498,556.15	892,780.26
Total Annual Costs	307,693.38	352,859.14	533,926.01	857,708.82	895,854.47	1,692,174.02
Emission Reductions-tpy	42.22	49.76	168.54	373.00	427.66	965.35
C/E-$/ton	7,287.31	7,091.68	3,167.90	2,299.48	2,094.77	1,752.91

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.30		
CEM Maintenance	30,000.00	From Initially Uncontrolled to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	5,760.00	9,000.00	34,120.00	61,960.00	62,560.00	133,480.00
Ammonia	4,210.06	4,966.92	61,116.77	135,904.39	155,535.55	349,765.78
Fuel Penalty (.5%)	2,402.03	2,402.03	6,755.54	15,069.64	20,220.08	42,480.47
Blower (if needed)	240.20	240.20	675.55	1,506.96	2,022.01	4,248.05
Operator	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	150,099.28	154,877.26	242,236.40	357,436.04	383,403.60	681,082.17
Total Annual Costs	268,449.28	312,282.76	464,663.39	751,188.49	780,701.92	1,480,475.93
Emission Reductions-tpy	31.67	37.32	126.41	279.75	320.75	724.01
C/E-$/ton	8,477.15	8,368.24	3,675.94	2,685.21	2,434.01	2,044.82

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.20		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	3,840.00	6,000.00	22,746.67	41,306.67	41,706.67	88,986.67
Ammonia	2,806.70	3,311.28	40,744.51	90,602.93	103,690.37	233,177.18
Fuel Penalty (.5%)	1,601.35	1,601.35	4,503.69	10,046.42	13,480.05	28,320.31
Blower (if needed)	160.14	160.14	450.37	1,004.64	1,348.01	2,832.03
Operator	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	110,855.19	114,300.88	172,973.78	250,915.71	268,251.06	469,384.07
Total Annual Costs	229,205.19	271,706.38	395,400.77	644,668.16	665,549.38	1,268,777.83
Emission Reductions-tpy	21.11	24.88	84.27	186.50	213.83	482.68
C/E-$/ton	10,856.84	10,921.38	4,692.00	3,456.66	3,112.49	2,628.63

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.10		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	900,000.00	1,197,000.00	1,691,460.00	2,994,315.20	3,021,280.00	6,079,040.00
Annualized Costs (10%, 15 yrs)	118,350.00	157,405.50	222,426.99	393,752.45	397,298.32	799,393.76
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	1,920.00	3,000.00	11,373.33	20,653.33	20,853.33	44,493.33
Ammonia	1,403.35	1,655.64	20,372.26	45,301.46	51,845.18	116,588.59
Fuel Penalty (.5%)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Blower (if needed)	80.07	80.07	225.18	502.32	674.00	1,416.02
Operator	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00
Taxes & Insurance	2,367.00	3,148.11	4,448.54	7,875.05	7,945.97	15,987.88
Total Operating Costs	71,611.09	73,724.49	103,711.16	144,395.38	153,098.51	257,685.97
Total Annual Costs	189,961.09	231,129.99	326,138.15	538,147.83	550,396.83	1,057,079.73
Emission Reductions-tpy	10.56	12.44	42.14	93.25	106.92	241.34
C/E-$/ton	17,995.90	18,580.78	7,740.20	5,771.01	5,147.95	4,380.08

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	1.00		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	11,400.00	22,133.33	55,066.67	123,733.33	144,533.33	323,733.33
Ammonia	10,958.76	21,286.80	52,822.80	123,936.48	138,127.68	294,073.20
Fuel Penalty (.5%)	8,006.75	8,006.75	22,518.47	50,232.12	67,400.25	141,601.56
Blower (if needed)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Operator	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	413,223.09	434,834.08	516,825.21	688,057.88	743,142.40	1,168,065.05
Total Annual Costs	496,068.09	545,159.95	705,096.39	924,694.76	1,040,197.74	1,872,905.05
Emission Reductions-tpy	18.35	40.30	100.30	235.64	262.36	559.33
C/E-$/ton	27,030.74	13,528.89	7,029.73	3,924.12	3,964.74	3,348.50
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6377	5281	3008	2101	2085	1921

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.90		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	10,260.00	19,920.00	49,560.00	111,360.00	130,080.00	291,360.00
Ammonia	9,862.88	19,158.12	47,540.52	111,542.83	124,314.91	264,665.88
Fuel Penalty (.5%)	7,206.08	7,206.08	20,266.62	45,208.91	60,660.23	127,441.40
Blower (if needed)	720.61	720.61	2,026.66	4,520.89	6,066.02	12,744.14
Operator	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	375,066.47	394,571.32	468,519.23	622,725.37	672,422.27	1,055,668.22
Total Annual Costs	457,911.47	504,897.19	656,790.41	859,362.25	969,477.61	1,760,508.22
Emission Reductions-tpy	16.52	36.27	90.27	212.08	236.13	503.39
C/E-$/ton	27,723.98	13,921.90	7,275.70	4,052.07	4,105.77	3,497.28
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6509	5404	3075	2133	2119	1955

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.80		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	9,120.00	17,706.67	44,053.33	98,986.67	115,626.67	258,986.67
Ammonia	8,767.01	17,029.44	42,258.24	99,149.18	110,502.14	235,258.56
Fuel Penalty (.5%)	6,405.40	6,405.40	18,014.78	40,185.69	53,920.20	113,281.25
Blower (if needed)	640.54	640.54	1,801.48	4,018.57	5,392.02	11,328.12
Operator	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	336,909.85	354,308.57	420,213.25	557,392.85	601,702.14	943,271.40
Total Annual Costs	419,754.85	464,634.44	608,484.43	794,029.73	898,757.48	1,648,111.40
Emission Reductions-tpy	14.68	32.24	80.24	188.52	209.89	447.46
C/E-$/ton	28,590.54	14,413.17	7,583.15	4,212.02	4,282.05	3,683.25
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6675	5558	3159	2173	2160	1997

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.70		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	7,980.00	15,493.33	38,546.67	86,613.33	101,173.33	226,613.33
Ammonia	7,671.13	14,900.76	36,975.96	86,755.54	96,689.38	205,851.24
Fuel Penalty (.5%)	5,604.73	5,604.73	15,762.93	35,162.48	47,180.18	99,121.09
Blower (if needed)	560.47	560.47	1,576.29	3,516.25	4,718.02	9,912.11
Operator	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	298,753.23	314,045.81	371,907.27	492,060.34	530,982.01	830,874.57
Total Annual Costs	381,598.23	424,371.68	560,178.45	728,697.22	828,037.35	1,535,714.57
Emission Reductions-tpy	12.85	28.21	70.21	164.95	183.65	391.53
C/E-$/ton	29,704.68	15,044.80	7,978.45	4,417.66	4,508.70	3,922.36
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6887	5757	3267	2224	2214	2051

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.60		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	6,840.00	13,280.00	33,040.00	74,240.00	86,720.00	194,240.00
Ammonia	6,575.26	12,772.08	31,693.68	74,361.89	82,876.61	176,443.92
Fuel Penalty (.5%)	4,804.05	4,804.05	13,511.08	30,139.27	40,440.15	84,960.94
Blower (if needed)	480.41	480.41	1,351.11	3,013.93	4,044.02	8,496.09
Operator	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	260,596.61	273,783.05	323,601.29	426,727.82	460,261.88	718,477.75
Total Annual Costs	343,441.61	384,108.92	511,872.47	663,364.70	757,317.23	1,423,317.75
Emission Reductions-tpy	11.01	24.18	60.18	141.39	157.42	335.60
C/E-$/ton	31,190.21	15,886.97	8,505.52	4,691.86	4,810.89	4,241.17
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	7171	6022	3411	2292	2286	2124

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.50		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	5,700.00	11,066.67	27,533.33	61,866.67	72,266.67	161,866.67
Ammonia	5,479.38	10,643.40	26,411.40	61,968.24	69,063.84	147,036.60
Fuel Penalty (.5%)	4,003.38	4,003.38	11,259.24	25,116.06	33,700.13	70,800.78
Blower (if needed)	400.34	400.34	1,125.92	2,511.61	3,370.01	7,080.08
Operator	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	222,439.99	233,520.30	275,295.32	361,395.31	389,541.75	606,080.92
Total Annual Costs	305,284.99	343,846.17	463,566.50	598,032.19	686,597.10	1,310,920.92
Emission Reductions-tpy	9.18	20.15	50.15	117.82	131.18	279.66
C/E-$/ton	33,269.94	17,066.02	9,243.41	5,075.73	5,233.97	4,687.50
C/E of WI	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
C/E of SCR+WI	7973	6735	3975	2763	2768	2612

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.40		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	4,560.00	8,853.33	22,026.67	49,493.33	57,813.33	129,493.33
Ammonia	4,383.50	8,514.72	21,129.12	49,574.59	55,251.07	117,629.28
Fuel Penalty (.5%)	3,202.70	3,202.70	9,007.39	20,092.85	26,960.10	56,640.62
Blower (if needed)	320.27	320.27	900.74	2,009.28	2,696.01	5,664.06
Operator	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	184,283.38	193,257.54	226,989.34	296,062.79	318,821.62	493,684.10
Total Annual Costs	267,128.38	303,583.41	415,260.52	532,699.67	615,876.97	1,198,524.10
Emission Reductions-tpy	7.34	16.12	40.12	94.26	104.94	223.73
C/E-$/ton	36,389.55	18,834.59	10,350.26	5,651.53	5,868.58	5,357.00
C/E of WI	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
C/E of SCR+WI	8569	7291	4277	2906	2918	2764

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.30		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	3,420.00	6,640.00	16,520.00	37,120.00	43,360.00	97,120.00
Ammonia	3,287.63	6,386.04	15,846.84	37,180.94	41,438.30	88,221.96
Fuel Penalty (.5%)	2,402.03	2,402.03	6,755.54	15,069.64	20,220.08	42,480.47
Blower (if needed)	240.20	240.20	675.55	1,506.96	2,022.01	4,248.05
Operator	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	146,126.76	152,994.79	178,683.36	230,730.28	248,101.49	381,287.27
Total Annual Costs	228,971.76	263,320.66	366,954.54	467,367.16	545,156.84	1,086,127.27
Emission Reductions-tpy	5.51	12.09	30.09	70.69	78.71	167.80
C/E-$/ton	41,588.88	21,782.20	12,194.99	6,611.20	6,926.27	6,472.83
C/E of WI	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00
C/E of SCR+WI	10371	8903	5508	3896	3932	3790

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.20		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	2,280.00	4,426.67	11,013.33	24,746.67	28,906.67	64,746.67
Ammonia	2,191.75	4,257.36	10,564.56	24,787.30	27,625.54	58,814.64
Fuel Penalty (.5%)	1,601.35	1,601.35	4,503.69	10,046.42	13,480.05	28,320.31
Blower (if needed)	160.14	160.14	450.37	1,004.64	1,348.01	2,832.03
Operator	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	107,970.14	112,732.03	130,377.38	165,397.77	177,381.37	268,890.45
Total Annual Costs	190,815.14	223,057.90	318,648.56	402,034.65	474,436.71	973,730.45
Emission Reductions-tpy	3.67	8.06	20.06	47.13	52.47	111.87
C/E-$/ton	51,987.56	27,677.42	15,884.46	8,530.55	9,041.64	8,704.50
C/E of WI	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00
C/E of SCR+WI	12357	10756	6514	4372	4434	4298

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON GAS TURBINES WITH HRSG

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.10		
CEM Maintenance	30,000.00		

From 42 to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	630,000.00	838,980.00	1,431,720.00	1,799,520.00	2,258,976.00	5,360,000.00
Annualized Costs (10%, 15 yrs)	82,845.00	110,325.87	188,271.18	236,636.88	297,055.34	704,840.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	1,140.00	2,213.33	5,506.67	12,373.33	14,453.33	32,373.33
Ammonia	1,095.88	2,128.68	5,282.28	12,393.65	13,812.77	29,407.32
Fuel Penalty (.5%)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Blower (if needed)	80.07	80.07	225.18	502.32	674.00	1,416.02
Operator	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00
Taxes & Insurance	1,656.90	2,206.52	3,765.42	4,732.74	5,941.11	14,096.80
Total Operating Costs	69,813.52	72,469.27	82,071.40	100,065.25	106,661.24	156,493.62
Total Annual Costs	152,658.52	182,795.14	270,342.58	336,702.13	403,716.58	861,333.62
Emission Reductions-tpy	1.84	4.03	10.03	23.56	26.24	55.93
C/E-$/ton	83,183.59	45,363.10	26,952.86	14,288.59	15,387.77	15,399.49
C/E of WI	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00
C/E of SCR+WI	18316	16314	9533	5801	5941	5822

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost for Centaur and Frame 3 = 80% of catalyst system cost.
Installation cost for larger units = 60% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	1.00		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	19,200.00	30,000.00	113,733.33	206,533.33	208,533.33	444,933.33
Ammonia	14,033.52	16,556.40	203,722.56	453,014.64	518,451.84	1,165,885.92
Fuel Penalty (.5%)	8,006.75	8,006.75	22,518.47	50,232.12	67,400.25	141,601.56
Blower (if needed)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Operator	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	424,281.95	438,212.36	726,086.19	1,102,093.97	1,188,478.17	2,160,970.36
Total Annual Costs	516,331.95	560,638.86	899,084.96	1,446,627.36	1,536,114.20	2,860,439.90
Emission Reductions-tpy	105.56	124.39	421.36	932.50	1,069.16	2,413.38
C/E-$/ton	4,891.45	4,507.03	2,133.79	1,551.34	1,436.75	1,185.24

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.90		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	17,280.00	27,000.00	102,360.00	185,880.00	187,680.00	400,440.00
Ammonia	12,630.17	14,900.76	183,350.30	407,713.18	466,606.66	1,049,297.33
Fuel Penalty (.5%)	7,206.08	7,206.08	20,266.62	45,208.91	60,660.23	127,441.40
Blower (if needed)	720.61	720.61	2,026.66	4,520.89	6,066.02	12,744.14
Operator	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	385,037.85	397,635.98	656,823.56	995,573.64	1,073,325.63	1,949,272.26
Total Annual Costs	477,087.85	520,062.48	829,822.33	1,340,107.03	1,420,961.66	2,648,741.80
Emission Reductions-tpy	95.00	111.95	379.22	839.25	962.24	2,172.04
C/E-$/ton	5,021.86	4,645.37	2,188.23	1,596.79	1,476.72	1,219.47

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.80		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	15,360.00	24,000.00	90,986.67	165,226.67	166,826.67	355,946.67
Ammonia	11,226.82	13,245.12	162,978.05	362,411.71	414,761.47	932,708.74
Fuel Penalty (.5%)	6,405.40	6,405.40	18,014.78	40,185.69	53,920.20	113,281.25
Blower (if needed)	640.54	640.54	1,801.48	4,018.57	5,392.02	11,328.12
Operator	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	345,793.76	357,059.59	587,560.94	889,053.31	958,173.08	1,737,574.17
Total Annual Costs	437,843.76	479,486.09	760,559.71	1,233,586.70	1,305,809.11	2,437,043.71
Emission Reductions-tpy	84.45	99.51	337.08	746.00	855.33	1,930.70
C/E-$/ton	5,184.87	4,818.30	2,256.29	1,653.60	1,526.68	1,262.26

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.70		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	13,440.00	21,000.00	79,613.33	144,573.33	145,973.33	311,453.33
Ammonia	9,823.46	11,589.48	142,605.79	317,110.25	362,916.29	816,120.14
Fuel Penalty (.5%)	5,604.73	5,604.73	15,762.93	35,162.48	47,180.18	99,121.09
Blower (if needed)	560.47	560.47	1,576.29	3,516.25	4,718.02	9,912.11
Operator	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	306,549.66	316,483.21	518,298.32	782,532.98	843,020.54	1,525,876.07
Total Annual Costs	398,599.66	438,909.71	691,297.09	1,127,066.37	1,190,656.57	2,225,345.61
Emission Reductions-tpy	73.89	87.07	294.95	652.75	748.41	1,689.37
C/E-$/ton	5,394.46	5,040.63	2,343.78	1,726.64	1,590.91	1,317.27

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.60		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	11,520.00	18,000.00	68,240.00	123,920.00	125,120.00	266,960.00
Ammonia	8,420.11	9,933.84	122,233.54	271,808.78	311,071.10	699,531.55
Fuel Penalty (.5%)	4,804.05	4,804.05	13,511.08	30,139.27	40,440.15	84,960.94
Blower (if needed)	480.41	480.41	1,351.11	3,013.93	4,044.02	8,496.09
Operator	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	267,305.57	275,906.83	449,035.70	676,012.65	727,867.99	1,314,177.97
Total Annual Costs	359,355.57	398,333.33	622,034.47	1,020,546.04	1,075,504.02	2,013,647.51
Emission Reductions-tpy	63.33	74.64	252.81	559.50	641.49	1,448.03
C/E-$/ton	5,673.90	5,337.07	2,460.45	1,824.03	1,676.56	1,390.61

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.50		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	9,600.00	15,000.00	56,866.67	103,266.67	104,266.67	222,466.67
Ammonia	7,016.76	8,278.20	101,861.28	226,507.32	259,225.92	582,942.96
Fuel Penalty (.5%)	4,003.38	4,003.38	11,259.24	25,116.06	33,700.13	70,800.78
Blower (if needed)	400.34	400.34	1,125.92	2,511.61	3,370.01	7,080.08
Operator	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	228,061.47	235,330.44	379,773.08	569,492.32	612,715.45	1,102,479.88
Total Annual Costs	320,111.47	357,756.94	552,771.85	914,025.71	960,351.48	1,801,949.42
Emission Reductions-tpy	52.78	62.20	210.68	466.25	534.58	1,206.69
C/E-$/ton	6,065.13	5,752.09	2,623.78	1,960.37	1,796.46	1,493.30

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.40		
CEM Maintenance	30,000.00	From Initially Uncontrolled to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	7,680.00	12,000.00	45,493.33	82,613.33	83,413.33	177,973.33
Ammonia	5,613.41	6,622.56	81,469.02	181,205.86	207,380.74	466,354.37
Fuel Penalty (.5%)	3,202.70	3,202.70	9,007.39	20,092.85	26,960.10	56,640.62
Blower (if needed)	320.27	320.27	900.74	2,009.28	2,696.01	5,664.06
Operator	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	188,817.38	194,754.06	310,510.46	462,971.99	497,562.90	890,781.78
Total Annual Costs	280,867.38	317,180.56	483,509.23	807,505.38	845,198.93	1,590,251.32
Emission Reductions-tpy	42.22	49.76	168.54	373.00	427.66	965.35
C/E-$/ton	6,651.97	6,374.62	2,868.77	2,164.89	1,976.32	1,647.33

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.30		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	5,760.00	9,000.00	34,120.00	61,960.00	62,560.00	133,480.00
Ammonia	4,210.06	4,966.92	61,116.77	135,904.39	155,535.55	349,765.78
Fuel Penalty (.5%)	2,402.03	2,402.03	6,755.54	15,069.64	20,220.08	42,480.47
Blower (if needed)	240.20	240.20	675.55	1,506.96	2,022.01	4,248.05
Operator	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	149,573.28	154,177.68	241,247.84	356,451.66	382,410.36	679,083.68
Total Annual Costs	241,623.28	276,604.18	414,246.61	700,985.05	730,046.39	1,378,553.22
Emission Reductions-tpy	31.67	37.32	126.41	279.75	320.75	724.01
C/E-$/ton	7,630.03	7,412.16	3,277.09	2,505.75	2,276.08	1,904.04

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.20		
CEM Maintenance	30,000.00	From Initially Uncontrolled to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	3,840.00	6,000.00	22,746.67	41,306.67	41,706.67	88,986.67
Ammonia	2,806.70	3,311.28	40,744.51	90,602.93	103,690.37	233,177.18
Fuel Penalty (.5%)	1,601.35	1,601.35	4,503.69	10,046.42	13,480.05	28,320.31
Blower (if needed)	160.14	160.14	450.37	1,004.64	1,348.01	2,832.03
Operator	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	110,329.19	113,601.30	171,985.22	249,931.33	267,257.81	467,385.58
Total Annual Costs	202,379.19	236,027.80	344,983.99	594,464.72	614,893.84	1,166,855.12
Emission Reductions-tpy	21.11	24.88	84.27	186.50	213.83	482.68
C/E-$/ton	9,586.16	9,487.26	4,093.74	3,187.47	2,875.60	2,417.47

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.10		
CEM Maintenance	30,000.00		

From Initially Uncontrolled to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	500,000.00	665,000.00	939,700.00	1,871,447.00	1,888,300.00	3,799,400.00
System + Installation	700,000.00	931,000.00	1,315,580.00	2,620,025.80	2,643,620.00	5,319,160.00
Annualized Costs (10%, 15 yrs)	92,050.00	122,426.50	172,998.77	344,533.39	347,636.03	699,469.54
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	1,920.00	3,000.00	11,373.33	20,653.33	20,853.33	44,493.33
Ammonia	1,403.35	1,655.64	20,372.26	45,301.46	51,845.18	116,588.59
Fuel Penalty (.5%)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Blower (if needed)	80.07	80.07	225.18	502.32	674.00	1,416.02
Operator	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00
Taxes & Insurance	1,841.00	2,448.53	3,459.98	6,890.67	6,952.72	13,989.39
Total Operating Costs	71,085.09	73,024.91	102,722.60	143,411.00	152,105.27	255,687.49
Total Annual Costs	163,135.09	195,451.41	275,721.37	487,944.39	499,741.30	955,157.03
Emission Reductions-tpy	10.56	12.44	42.14	93.25	106.92	241.34
C/E-$/ton	15,454.55	15,712.54	6,543.67	5,232.64	4,674.16	3,957.76

(a) uncontrolled to 25 ppm. (b) uncontrolled to 9 ppm.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	1.00		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	11,400.00	22,133.33	55,066.67	123,733.33	144,533.33	323,733.33
Ammonia	10,958.76	21,286.80	52,822.80	123,936.48	138,127.68	294,073.20
Fuel Penalty (.5%)	8,006.75	8,006.75	22,518.47	50,232.12	67,400.25	141,601.56
Blower (if needed)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Operator	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00	350,400.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	412,854.89	434,343.74	515,988.45	687,466.29	742,399.76	1,166,302.95
Total Annual Costs	477,289.89	520,152.75	662,421.59	894,523.56	1,002,323.19	1,783,037.95
Emission Reductions-tpy	18.35	40.30	100.30	235.64	262.36	559.33
C/E-$/ton	26,007.51	12,906.30	6,604.27	3,796.08	3,820.38	3,187.83
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6181	5085	2892	2070	2051	1884

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.90		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	10,260.00	19,920.00	49,560.00	111,360.00	130,080.00	291,360.00
Ammonia	9,862.88	19,158.12	47,540.52	111,542.83	124,314.91	264,665.88
Fuel Penalty (.5%)	7,206.08	7,206.08	20,266.62	45,208.91	60,660.23	127,441.40
Blower (if needed)	720.61	720.61	2,026.66	4,520.89	6,066.02	12,744.14
Operator	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00	315,360.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	374,698.27	394,080.99	467,682.47	622,133.77	671,679.63	1,053,906.12
Total Annual Costs	439,133.27	479,890.00	614,115.61	829,191.04	931,603.06	1,670,641.12
Emission Reductions-tpy	16.52	36.27	90.27	212.08	236.13	503.39
C/E-$/ton	26,587.07	13,232.36	6,802.96	3,909.81	3,945.37	3,318.76
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6292	5187	2946	2098	2081	1914

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.80		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	9,120.00	17,706.67	44,053.33	98,986.67	115,626.67	258,986.67
Ammonia	8,767.01	17,029.44	42,258.24	99,149.18	110,502.14	235,258.56
Fuel Penalty (.5%)	6,405.40	6,405.40	18,014.78	40,185.69	53,920.20	113,281.25
Blower (if needed)	640.54	640.54	1,801.48	4,018.57	5,392.02	11,328.12
Operator	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00	280,320.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	336,541.65	353,818.23	419,376.49	556,801.26	600,959.50	941,509.30
Total Annual Costs	400,976.65	439,627.24	565,809.63	763,858.53	860,882.93	1,558,244.30
Emission Reductions-tpy	14.68	32.24	80.24	188.52	209.89	447.46
C/E-$/ton	27,311.51	13,637.43	7,051.33	4,051.97	4,101.60	3,482.42
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6430	5315	3014	2133	2118	1951

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.70		
CEM Maintenance	30,000.00		

From 42 to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	7,980.00	15,493.33	38,546.67	86,613.33	101,173.33	226,613.33
Ammonia	7,671.13	14,900.76	36,975.96	86,755.54	96,689.38	205,851.24
Fuel Penalty (.5%)	5,604.73	5,604.73	15,762.93	35,162.48	47,180.18	99,121.09
Blower (if needed)	560.47	560.47	1,576.29	3,516.25	4,718.02	9,912.11
Operator	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00	245,280.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	298,385.03	313,555.47	371,070.51	491,468.75	530,239.37	829,112.47
Total Annual Costs	362,820.03	399,364.48	517,503.65	698,526.02	790,162.80	1,445,847.47
Emission Reductions-tpy	12.85	28.21	70.21	164.95	183.65	391.53
C/E-$/ton	28,242.93	14,158.25	7,370.65	4,234.75	4,302.47	3,692.83
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6608	5478	3101	2179	2165	1999

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.60		
CEM Maintenance	30,000.00		

From 42 to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	6,840.00	13,280.00	33,040.00	74,240.00	86,720.00	194,240.00
Ammonia	6,575.26	12,772.06	31,693.68	74,361.89	82,876.61	176,443.92
Fuel Penalty (.5%)	4,804.05	4,804.05	13,511.08	30,139.27	40,440.15	84,960.94
Blower (if needed)	480.41	480.41	1,351.11	3,013.93	4,044.02	8,496.09
Operator	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00	210,240.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	260,228.41	273,292.72	322,764.53	426,136.23	459,519.24	716,715.65
Total Annual Costs	324,663.41	359,101.73	469,197.67	633,193.50	719,442.67	1,333,450.65
Emission Reductions-tpy	11.01	24.18	60.18	141.39	157.42	335.60
C/E-$/ton	29,484.83	14,852.66	7,796.42	4,478.46	4,570.29	3,973.39
C/E of WI	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00	1,500.00
C/E of SCR+WI	6845	5697	3217	2239	2229	2063

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.50		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	5,700.00	11,066.67	27,533.33	61,866.67	72,266.67	161,866.67
Ammonia	5,479.38	10,643.40	26,411.40	61,968.24	69,063.84	147,036.60
Fuel Penalty (.5%)	4,003.38	4,003.38	11,259.24	25,116.06	33,700.13	70,800.78
Blower (if needed)	400.34	400.34	1,125.92	2,511.61	3,370.01	7,080.08
Operator	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00	175,200.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	222,071.79	233,029.96	274,458.55	360,803.72	388,799.11	604,318.82
Total Annual Costs	286,506.79	318,838.97	420,891.69	567,860.99	648,722.54	1,221,053.82
Emission Reductions-tpy	9.18	20.15	50.15	117.82	131.18	279.66
C/E-$/ton	31,223.50	15,824.84	8,392.49	4,819.65	4,945.25	4,366.16
C/E of WI	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
C/E of SCR+WI	7582	6345	3743	2700	2699	2539

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.40		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	4,560.00	8,853.33	22,026.67	49,493.33	57,813.33	129,493.33
Ammonia	4,383.50	8,514.72	21,129.12	49,574.59	55,251.07	117,629.28
Fuel Penalty (.5%)	3,202.70	3,202.70	9,007.39	20,092.85	26,960.10	56,640.62
Blower (if needed)	320.27	320.27	900.74	2,009.28	2,696.01	5,664.06
Operator	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00	140,160.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	183,915.18	192,767.21	226,152.58	295,471.20	318,078.99	491,922.00
Total Annual Costs	248,350.18	278,576.22	372,585.72	502,528.47	578,002.41	1,108,657.00
Emission Reductions-tpy	7.34	16.12	40.12	94.26	104.94	223.73
C/E-$/ton	33,831.49	17,283.12	9,286.60	5,331.44	5,507.68	4,955.33
C/E of WI	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
C/E of SCR+WI	8080	6803	3987	2827	2833	2673

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.30		
CEM Maintenance	30,000.00		

From 42 to 25 or 9 ppm

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	3,420.00	6,640.00	16,520.00	37,120.00	43,360.00	97,120.00
Ammonia	3,287.63	6,386.04	15,846.84	37,180.94	41,438.30	88,221.96
Fuel Penalty (.5%)	2,402.03	2,402.03	6,755.54	15,069.64	20,220.08	42,480.47
Blower (if needed)	240.20	240.20	675.55	1,506.96	2,022.01	4,248.05
Operator	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00	105,120.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	145,758.56	152,504.45	177,846.60	230,138.69	247,358.86	379,525.17
Total Annual Costs	210,193.56	238,313.46	324,279.74	437,195.96	507,282.28	996,260.17
Emission Reductions-tpy	5.51	12.09	30.09	70.69	78.71	167.80
C/E-$/ton	38,178.14	19,713.57	10,776.78	6,184.41	6,445.07	5,937.27
C/E of WI	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00
C/E of SCR+WI	9719	8253	5121	3790	3818	3668

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.20		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	2,280.00	4,426.67	11,013.33	24,746.67	28,906.67	64,746.67
Ammonia	2,191.75	4,257.36	10,564.56	24,787.30	27,625.54	58,814.64
Fuel Penalty (.5%)	1,601.35	1,601.35	4,503.69	10,046.42	13,480.05	28,320.31
Blower (if needed)	160.14	160.14	450.37	1,004.64	1,348.01	2,832.03
Operator	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00	70,080.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	107,601.94	112,241.69	129,540.62	164,806.17	176,638.73	267,128.35
Total Annual Costs	172,036.94	198,050.70	275,973.76	371,863.44	436,562.15	883,863.35
Emission Reductions-tpy	3.67	8.06	20.06	47.13	52.47	111.87
C/E-$/ton	46,871.44	24,574.49	13,757.14	7,890.37	8,319.84	7,901.15
C/E of WI	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00
C/E of SCR+WI	11380	9781	5934	4213	4263	4115

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

COST FOR SCR ON PEAKER GAS TURBINES

Catalyst -$/cu ft	400.00	Catalyst Life-yrs	3
Ammonia-$/lb	0.18	Operator-$/y	350,400.00
Fuel Cost-$/MMBTU	3.69		
Plant factor	0.10		
CEM Maintenance	30,000.00	From 42 to 25 or 9 ppm	

Model	Centaur-T(a)	Centaur-T(b)	Frame 3	Frame 5	Frame 6	Frame 7
Nominal Size-MW	4.5	4.5	10.45	26.30	38.30	83.50
Catalyst System Cost-$	350,000.00	466,100.00	795,400.00	1,124,700.00	1,411,860.00	3,350,000.00
System + Installation	490,000.00	652,540.00	1,113,560.00	1,574,580.00	1,976,604.00	4,690,000.00
Annualized Costs (10%, 15 yrs)	64,435.00	85,809.01	146,433.14	207,057.27	259,923.43	616,735.00
Operating Costs						
CEM Maintenance	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00	30,000.00
Catalyst Replacement	1,140.00	2,213.33	5,506.67	12,373.33	14,453.33	32,373.33
Ammonia	1,095.88	2,128.68	5,282.28	12,393.65	13,812.77	29,407.32
Fuel Penalty (.5%)	800.68	800.68	2,251.85	5,023.21	6,740.03	14,160.16
Blower (if needed)	80.07	80.07	225.18	502.32	674.00	1,416.02
Operator	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00	35,040.00
Taxes & Insurance	1,288.70	1,716.18	2,928.66	4,141.15	5,198.47	12,334.70
Total Operating Costs	69,445.32	71,978.94	81,234.64	99,473.66	105,918.60	154,731.52
Total Annual Costs	133,880.32	157,787.95	227,667.78	306,530.93	365,842.02	771,466.52
Emission Reductions-tpy	1.84	4.03	10.03	23.56	26.24	55.93
C/E-$/ton	72,951.35	39,157.22	22,698.23	13,008.22	13,944.17	13,792.79
C/E of WI	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00	3,000.00
C/E of SCR+WI	16361	14364	8372	5483	5598	5456

(a) controlled from 42 to 25 ppm. (b) controlled from 42 to 9 ppm.
Installation cost = 40% of catalyst system cost.

APPENDIX D

Summary of Significant Comments and Responses

SUMMARY OF SIGNIFICANT COMMENTS AND RESPONSES

Included below are the oral and written comments presented at the May and September workshops and the staff responses.

Comment 1 - Solar Gas Turbines

The efficiency correction in the current proposal is based on simple cycle output. Efficiency correction should include all displaced power, both thermal and electrical.

Response

The efficiency correction is based on simple cycle output to avoid penalizing more efficient, higher-firing temperature gas turbines. Gas turbines that are used in cogeneration produce both electrical and thermal energy. However, the displaced energy may not be from a dirtier source, especially with the adoption of RACT/BACT for utility and industrial boilers.

Comment 2 - Solar Gas Turbines

Proposed Limits for Gas Turbines Under 10 MW

	Displaced Limits*	
	RACT	BARCT
Now	Currently Available**	42
1995	42	30
2000	30	15

* Displaced means useful electrical and thermal energy.
** 42 ppmv for "displaced" cogeneration applications; current dry combustion for simple cycle units when water is not available.

Response

Our RACT limit is based on demonstrated technology. Our BARCT limit is based on what is achievable but not necessarily demonstrated. Some gas turbine manufacturers have stated that 25 ppm is achievable by the mid-1990's. If the level is not achievable with combustion modifications, retrofit with SCR is available.

Comment 3 - Solar Gas Turbines

Based on the following assumptions, the costs for an SCR system for our Saturn (1 MW), Centaur (4 MW), and Mars (9 MW) gas turbines are as follows:

	Gas Turbine Cost	Gas Turbine + HRB	TPY Emission Reduction from 42 to 9 ppm	$/Ton	Present Worth* $/ton ($1000)
Saturn	750	1500	11	10,000	550
Centaur	1700	3400	35	7,500	1313
Mars	4500	7500	65	5,000	1625

SCR Cost / gas turbine cost	SCR Cost / gas turbine + HRSG cost
73	37
77	39
36	22

* Present worth factor = 5

Response

The staff acknowledges the higher costs of an SCR system associated with smaller gas turbines (less than 10 MW). Therefore, the limit has been raised to 25 ppm for units equal to or greater than 2.9 MW and to 42 ppm for units less than 2.9 MW.

Comment 4 - Solar Gas Turbines

There is no low-NOx combustor available for the Saturn (1 MW) gas turbine and water injection has demonstrated only 65 ppm. These gas turbines should be exempted.

Response

In 1986, Garrett Auxiliary Power Division submitted test data to the SCAQMD that showed that their 1M831-800 could achieve 42 ppm on natural gas with water injection. Furthermore, Garret asked the SCAQMD to consider a limit no less than 42 ppm for gas turbines under 1 MW. Solar has been developing modifications to allow the combustor to withstand water injection to 42 ppm. Currently Solar is working with the Navy to achieve 42 ppm on its Saturn installation in Ventura County. Therefore, we believe that 42 ppm is achievable.

Comment 5 - Solar Gas Turbines

The staff report is written with a predisposition to SCR. The ARB should look more closely at the real and comparative costs associated with the use of SCR. The staff report should point out that over one third of permitted small turbine SCR projects are not operational and have been abandoned. The report should also recommend the use of dry low-NOx combustors.

Response

The discussion on SCR is lengthier than that of the other technologies in order to address concerns such as the remoteness of the gas turbine, exhaust gas temperature, the use of distillate oil fuel, and the assumptions used in the cost analyses. With regards to recommending a control technology, our policy is to remain neutral and allow the operator to choose the technology.

Comment 6 - Solar Gas Turbines

Given the variable supplementary firing systems integrated into most cogeneration units, it is difficult, as a practical matter, to locate the catalyst where it would be effective or even survive. Duct firing temperatures ranging from 1600-1800 ^{o} F are too high, whereas the temperatures of less than 500 ^{o} F associated with steam generation are inadequate for the necessary chemical reaction to occur. Variable load cycle and exhaust gas temperatures may result in early catalyst failure or, at a minimum, sub-optimal operation. Also, locating the catalyst before the duct burner still means that NOx emissions are being produced within the burner. Moreover, any modification in existing duct work has the potential for creating skewed velocity or temperature profiles, with the effect that the injected ammonia may not mix properly.

Response

Exemptions would be allowed for installations that are shown to be infeasible or highly cost-ineffective. Regarding the placement of the SCR catalyst upstream of the duct burner, it is true that emissions from the duct burner would remain uncontrolled. However, with the use of the two alternative control technologies, low-NOx combustors and water injection, emissions from the duct burner would also remain uncontrolled.

Comment 7 - US Borax

US Borax operates a 45 MW Westinghouse 251B10 Combustion turbine in a cogeneration application in Kern County. We have investigated the possibility of an SCR retrofit. To date however, we have not found an SCR manufacturer that can provide a system which will operate in the 950-1050 °F temperature range of our unit.

Response
SCR catalysts are available for temperatures up to 960 °F. For higher temperature application, the system comes with a unit to cool the exhaust gas by air dilution. This system is ideal for simple cycle and cogeneration units. The control system would be placed between the gas turbine and duct burner. See the "SCR" section of the staff report for more information.

Comment 8 - U.S. Borax

The installation of an SCR system for our 45 MW gas turbine would cost at least $8,000,000 plus $10,000,000 in down time. Regarding low-NOx combustors, the system being developed for our unit is expected to achieve 25 ppm.

Response
Districts have the authority to grant exemptions on a case-by-case basis.

Comment 9 - US Borax

Low NOx combustor systems are an emerging technology and it would be imprudent to establish lower NOx requirements for retrofit before this technology is initially developed and tested. The expected NOx emissions from the Westinghouse low NOx combustor is expected to be 25 ppmv. We recommend CARB change the BARCT level to 25 ppmv for large gas turbines.

Response
For large gas turbines operating full time, the alternative SCR limit is generally cost-effective. Therefore, this alternative is a viable option for those who cannot meet the non-SCR limit.

Comment 10 - Ventura County APCD

Ventura County has four gas turbines installed with SCR, but two of those are operating at 12 and 15 ppmv NOx. The BARCT limit is 9 ppmv. It is our concern that the SCR units for these turbines, and possibly others in the state, may not be designed to meet the 9 ppmv limit. Requiring compliance with limits not designed for the BARCT limit may mean replacement of an existing SCR unit. The cost effectiveness of such action could be exorbitant, and the policy of such a requirement might not be defendable. Therefore, an exemption should be provided for existing limits equipped with SCR that cannot meet the 9 ppmv limit due to the design of the SCR unit.

Response

The 9 ppm limit is a reference limit based on a standard of 25 percent efficiency. Units that are more efficient would have a higher compliance limit. Thus, the 12 ppm unit may already be in compliance. As for those units that are not in compliance, increasing the water injection rate or replacing the combustors with low-NOx combustors would be the most economical choices if there is no room for catalyst expansion. If the cost-effectiveness is exorbitant, an exemption for these units can be incorporated at the district level on a case-by-case basis.

Comment 11 - Ventura County APCD

The staff report indicates that the determination for the 12 ppmv BARCT is technology forcing. Is this the intent of BARCT?

Response

The criteria for a BARCT determination requires control technology that is achieved or achievable but not necessarily demonstrated. In the case of large gas turbines, the alternate limit of 9 ppm is achievable by almost all units. It is not technology forcing. The alternate limit of 15 ppm has been demonstrated with low NOx burners by Siemens on commercial size units. Also the South Coast Air Quality Management District has received source test data on a GE LM5000 and a GE LM2500 that achieved the 15 ppm reference limit with steam or water injection.

Comment 12 - Ventura County APCD

It has been our understanding that the older aeroderivative engines were limited to not more than 42 ppmv with water injection. Is the staff report reference to aeroderivative engines in regards to newer generation engines?

Response

Aeroderivatives, old and new, probably would not use water injection to achieve high emission reductions if high pressure steam is available. The staff recognizes that one LM2500 operator submitted test data to the SCAQMD based on water injection to meet the Rule 1134 limits. However, the engine durability is not known and the CO emissions are very high. The staff recognizes that there is uncertainty as to which models can achieve emission levels down to 15 ppm with water or steam injection and the uncertainty is reflected in the staff report.

Comment 13 - Ventura County APCD

Has the Wheelabrator data been verified as accurate?

Response

The results of the Wheelabrator test are similar to the results of a test performed earlier on an LM5000 (same family) with steam injection. The LM5000 tests are described in detail in ASME 86-GT-231.

Comment 14 - Ventura County APCD

Section VII.C. appears to allow the granting of administrative variances. Is this legal, or should each of these sources be required to obtain a variance from the district hearing board?

Response

We believe that Section VII.C. is a short-term exemption, not an administrative variance.

Comment 15 - Brian T. Kelleher and Associates

Caution must be used in using the SCAQMD emission limits and costs.

Response

We have modified the emission limits to standards that can be supported by our independent cost analysis.

Comment 16 - IPT

Will there be an early compliance limit of some agreed ahead of time limit similar to Rule 1134?

Response

Rule 1134 has this provision because the non-SCR limit for units 10 MW and over depends on the demonstration of an LM5000 by December 31, 1990, and a LM2500 by December 31, 1991. If either demonstration fails, then all large units are subject to compliance with the 9 ppm limit by August 1, 1993. This compliance limit and date would not apply to anyone who demonstrates compliance with the specific final reference limit by February 1, 1992.

Comment 17 - PG&E

Peaking units greater than 4 MW should be allowed to operate at a 5% capacity factor (on an aggregate basis), rather than being restricted in service hours.

Response

Based on all the suggested capacity limits submitted at the workshop, we believe that 877 hours is a fair cut-off limit.

Comment 18 - Turlock Irrigation District

Exemptions for RACT/BARCT should be based on pounds per day rather than hours per year.

Response

If the exemption were based on pounds per day, there is still the issue of what to use as a basis - a small or large gas turbine based upon 1000 or 200 hours? An exemption based on hours per year does not give any operator an advantage over another. Enforcement is also easier because an exemption based on pounds per day would require the use of continuous monitors for NOx while a time basis exemption would only require the monitoring of elapsed running time.

Comment 19 - Turlock Irrigation District

Most peaking units operate up to a 10% capacity factor. Therefore, I ask that the exemption, while expressed in tons/year, be equivalent to 876 hours/year.

Response

See Comment 17.

Comment 20 - Turlock Irrigation District

We would like to see the determination address the issue of offsets. Specifically, the exemption limit, whether in tons/year or hours/year should be added on top of acquired offsets before BARCT is required.

Response

BARCT is necessary to attain the state ambient air quality standards. Allowing the use of offsets as a means of exempting a source from BARCT is inappropriate and would negate the effectiveness of the rule.

Comment 21 - Turlock Irrigation District

The determination is titled "Reasonably Available... Best Available...". Dry low NOx combustors are still in the development stage and I would not call them reasonably or best available.

Response

See Comment 11

Comment 22 - Turlock Irrigation District

The development program is currently limited to Frame 7 machines. The development program for the Frame 5 has not begun. The compliance schedule for Frame 5 machines should be two years after low NOx combustors become available for Frame 7 machines.

Response

The combustors for the Frame 5 are expected to be available by the suggested compliance date of the rule, which is later than the compliance date in SCAQMD Rule 1134.

Comment 23 - Modesto Irrigation District

We are concerned that these RACT/BARCT determinations will be adopted by the district as is without incorporating special exemptions and allowances tailored for the specific district.

Response

Both RACT and BARCT are based on economics. The determination provides flexibility to the districts to incorporate exemptions based on local conditions.

Comment 24 - Modesto Irrigation District

CARB should comply with the requirements of Section 41514.8, which requires that certain findings be made before the adoption of rules or regulations which affect the operation of existing powerplants. Most importantly, that section requires that there be written findings as to the relative cost of achieving the emission reductions from the proposed rule compared to the cost of feasible reductions from sources other than powerplants.

Response

Section 41514.8 is applicable to the actual district rule adoption process. Therefore, the RACT/BARCT determination is not subject to the requirements of Section 41514.8. However, the information contained in the RACT/BARCT determination should be useful to the districts in their rule adoption process. For example, the staff report provides costs for both cogeneration and for peaker units in the "Cost Effectiveness" section. Peaker units are commonly owned by utilities for generating power. Cogeneration units are commonly owned by industrial parties.

Comment 25 - Modesto Irrigation District

We recommend setting the yearly operating limit for peakers in terms of 600 equivalent full load hours/year. This represents a 6.85% capacity factor. This limit is a major concession from our present permitting condition which is equivalent to 900 hours of operation per year at full load.

Response
See Comment 17.

Comment 26 - Modesto Irrigation District

There should be an exemption for fuel use during Western System Coordinating Council emergencies. There are times when emergencies occur such as earthquakes and fires under transmission lines where local peaking gas turbine operation is critical to help meet load whether in our service territory or other areas affected by the event.

Response
When the governor declares a state of emergency, gas turbines used in public service that are located in disaster areas are exempt from the time restrictions.

Comment 27 - Modesto Irrigation District

The compliance schedule for BARCT should be lengthened to allow technology to catch up with the simple cycle machines and for the technology to be proven.

Response
The control technology for simple cycle units is already proven. See Comment 7.

Comment 28 - TOSCO

What is the 15 minute averaging time based on?

Response
The SCAQMD NOx rules and the industrial boiler RACT/BARCT determination are both based on 15 minute averaging times. Therefore, 15 minutes was chosen for the averaging time.

Comment 29 - City of Santa Clara

Historically, peaking units have been limited to at or below 1000 hours/years. It is not clear to us how reducing our hours of operation to 200 hours will benefit air quality.

Response

The RACT/BARCT requirements do not limit your operating time. Any limitation of operating time is self-imposed. Instead, the time requirement is a trigger for BARCT.

Comment 30 - City of Santa Clara

We feel that under BARCT there should be separate limits for industrial and aeroderivative gas turbines because each type of technology will have its own physical limit as to available level of control.

Response

There is no need for separate limits because both industrial and aeroderivative gas turbines can be controlled to 9 ppm with SCR. The alternative level is optional.

Comment 31 - City of Santa Clara

The exhaust temperature from the stack at a cogeneration plant using an Allison gas turbine is too low to apply SCR and the exhaust gas temperature from a Frame 5 peaking unit is too high (920 °F).

Response

The catalyst in the cogeneration unit can be placed upstream of the boiler where the exhaust gas temperature is 950-1080 °F. A high temperature catalyst along with air dilution can then be employed for both the Allison and Frame 5. See Comment 7.

Comment 32 - Northern California Power Agency

Northern California Power Agency operates five Frame 5 peaking units. The exhaust temperature of a Frame 5 is nearly 1000 °F which exceeds the temperature limits for SCR.

Response

See Comment 7.

Comment 33 - Hershey Chocolate

We have an Allison 5.5 MW gas turbine that cannot meet the 15 ppm limit without SCR.

Response

The limit has been changed to 25 ppm which in most cases can be achieved without SCR.

Comment 34 - IPT

Ammonia slip concerns are heightened with so-called high temperature SCR catalysts because they operate outside the optimum catalyst performance temperature window.

Response

High temperature catalysts operate at optimum efficiency at a higher temperature range than conventional catalysts. Therefore, ammonia slip will not increase, as long as operation is maintained within the specified high temperature window.

Comment 35 - Exxon

Exxon supports a BARCT limit of 42 ppm for gas-fired turbines over 0.3 MW, similar to control Scenario 1 for units 2.9-10 MW. However, Exxon feels that the proposed BARCT limits of 9-12 ppm for gas-fired turbines over 10 MW are unreasonable and not cost-effective, and represent BACT limits, based on recent air permitting experience.

Response

We believe that the limits of 25 ppm for units 2.9 to less than 10 MW and 9-15 ppm for units greater than or equal to 10 MW are reasonable and cost-effective for most cases. An exemption is provided for units shown to be technologically infeasible to retrofit.

Comment 36 - Exxon

Assuming steam injection has already been installed as a cost-effective first step, installation of SCR would only reduce NOx emissions by an additional 25 percent over steam injection. Also, the incremental cost increase from adding the SCR does not include potential major modifications to the HRSG or substantial process debits for extending a process unit downtime to install an SCR unit.

Response

If steam injection has been added to achieve the non-SCR limit, then no additional controls are required. Therefore, the 25 percent incremental reduction from adding the SCR is not an issue. Regarding SCR costs, the staff report does not include modifications to the boiler. If the operator can show that it would be infeasible to place the SCR unit upstream of the HRSG and show that the costs for retrofit within the boiler are unreasonable, then the district could exempt the unit from the SCR limit.

Comment 37 - Exxon

We understand that low-NOx combustors might be incompatible with steam injection. We are also concerned that staged combustors might be larger than the existing combustors on our GE Frame 3's and Frame 5. As a result, major structural changes and extended process unit downtimes might be required to retrofit this new technology.

Response

Dry low-NOx combustors were developed to achieve low NOx levels without water or steam injection when operating on natural gas. However, in the current models water or steam would be required when burning distillate oil because the combustor must operate in the conventional mode. Manufacturers are experimenting with operating in the premix mode with distillate fuels and have reported NOx emissions of 20-30 ppm with test rigs. Ken Gessler of GE has verified that low NOx combustors intended for retrofit would be designed to fit in the same space as the existing combustor.

Comment 38 - Exxon

The proposed 15-minute averaging period is impractical. It does not allow enough time for equipment breakdowns.

Response

The 15-minute averaging period is not intended to allow time for equipment breakdowns. Breakdowns should be handled through the variance procedure.

Comment 39 - Kleinfelder

A gas turbine can only use the energy that is represented by the "lower heating value" (LHV). Therefore, the fuel rate for a gas turbine is the same regardless of the fuel being used. However, fuel rate based on the "higher heating value" (HHV) depends on the fuel. I recommend that this standard use the same criteria as CFR 60.332 which is LHV on a basis of 14.4 kilojoules per watt hour (25% efficiency).

Response

For consistency with SCAQMD Rule 1134, we prefer to use HHV. Also workshop participants noted that almost all units are operating on natural gas and that the gas company reports fuel quality in terms of HHV.

Comment 40 - San Joaquin Valley UAPCD

The cost analyses should consider the higher cost of low sulfur fuels in areas where currently such fuels are not readily available, such as the San Joaquin Valley.

Response

We believe that the cost of low sulfur fuel oil in the San Joaquin Valley will be about the same price as low sulfur fuel oil in populated areas before the final compliance date of the gas turbine rules. By October 1993 low sulfur fuel oil must be used by diesel vehicles statewide. The gas turbine regulations are expected to be implemented in 1996, which is three years after low sulfur fuel oil becomes widely available throughout California.

Comment 41 - San Joaquin Valley UAPCD

The determination limits thermal stabilization time to startup periods only. The determination should also include a shutdown period.

Response

We believe that shutdown periods are not a problem. However, text was added in the staff report informing districts that they may include a shutdown period in the thermal stabilization period if deemed necessary.

Comment 42 - San Joaquin Valley UAPCD

The determination should contain specific language or a recommendation to exempt modifications which are solely for the purpose of complying with RACT/BARCT requirements from the NSR Rule.

Response

The districts already have the freedom to exempt compliance with RACT/BARCT requirements from the NSR Rule.

Comment 43 - Southern California Edison

We presently have no emission controls on our peaker units. Each aggregate set of units adds up to 120 MW. We use these gas turbines less than 150 hours per year per set. We would like an exemption for all emission requirements for low usage units.

Response

We recognize that cost-effectiveness increases with lower usage. The text in the staff report indicates that districts may wish to add low-usage exemption levels for units greater than 4 MW.