December 30, 1999

MEMORANDUM

FROM: Sims Roy
Emission Standards Division
Combustion Group

TO: Docket A-95-51

SUBJECT: Oxidation Catalyst Costs for New Stationary Combustion Turbines

The purpose of this memorandum is to summarize information on the cost of oxidation catalyst control for new stationary combustion turbines. Catalyst vendors provided information to EPA on the costs of acquiring, installing, and operating oxidation catalysts for HAP reduction for various turbines; these costs were applied to seven model turbines ranging in size from 1.13 megawatts (MW) to 170 MW. The total capital and annual costs were then estimated using methodologies from the OAQPS Control Cost Manual. A detailed description of the cost methodologies is given in Attachment A.

The total capital and annual costs for each model turbine are presented in the table below. The annual costs were estimated for both the guaranteed life of the catalyst (3 years) and the "typical" life of the catalyst (6 years).

Model Turbine	**Total Capital Cost ($)**[a]	**Total Annual Cost ($)**	
		3-Year Costs	**6-Year Costs**
GE PG 7121EA, 85.4 MW	3,272,268	1,157,833	956,998
GE PG 7231FA, 170 MW	4,753,816	1,673,902	1,382,131
GE PG 6561B, 39.6 MW	1,736,369	631,334	524,762
GE LM25000, 27 MW	1,103,989	415,818	348,060
Solar Centaur 40, 3.5 MW	677,525	268,560	226,974
Solar Mars T12000, 9 MW	485,196	202,673	172,898

Model Turbine	**Total Capital Cost ($)**[a]	**Total Annual Cost ($)**	
		3-Year Costs	**6-Year Costs**
Solar Saturn T1500, 1.13 MW	364,154	161,431	139,086

[a]Costs reflect mid-1998 figures.

Attachment A

MEMORANDUM

DATE: May 14, 1999

SUBJECT: Stationary Combustion Turbines Control Options Cost Information Summary

The purpose of this memorandum is to summarize the cost information that has been received for control options to date. This information will be used with model turbines developed for the Stationary Combustion Turbines source category as part of estimating the national impacts of viable regulatory options.

Background

In support of MACT determinations for new and existing combustion turbines, a set of model turbines has been developed that can be used to evaluate the national impact of control options being considered. The following approach will be used to determine national impacts:

1) Develop model turbines
2) Estimate control costs for each control option for each model turbine
3) Estimate emission reduction for each control option for each model turbine
4) Relate model turbines to turbines in the EPA Inventory Database for Stationary Combustion Turbines
5) Extrapolate from the inventory database population to the national population
6) Determine regulatory options
7) Estimate economic impacts for each regulatory option

Cost information has been received that will be used to estimate the control costs for each option being considered on a model turbine basis. This memorandum reflects the cost information that has been received to date. Any additional cost data received from vendors will be incorporated, as necessary, at a later time.

Cost Information

The methodology in the OAQPS Control Cost Manual will be used to determine the annual cost of control technologies. The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. Direct cost inputs are required for certain key elements, such as the capital costs of the control device. Other costs, such as installation, are then estimated based on percentages of the direct cost inputs.

In the OAQPS methodology, five cost categories are used to describe the annual cost of a control device. These are as follows:

1) Purchased Equipment Costs (PEC), which include the capital cost of the control device and auxiliary equipment, instrumentation, sales tax, and freight;
2) Direct Costs for Installation (DCI), which are the construction-related costs associated with installing the catalyst;
3) Indirect Costs for Installation (ICI), which include expenses related to engineering and start-up;
4) Direct Annual Costs (DAC), which include annual increases in operating and maintenance costs due to the addition of the control device; and
5) Indirect Annual Costs (IAC), which are the annualized cost of the control device system and the costs due to tax, overhead, insurance, and administrative burdens.

The cost that will be used in model turbine analyses is the total annual cost, which is the sum of the Direct Annual Costs (DAC) and the Indirect Annual Costs (IAC). The following information reflects the capital and operating costs that have thus far been obtained from vendors on the control technologies under consideration. Cost estimates are in 1998 dollars unless otherwise indicated.

Catalytic Systems

- **CO Oxidation Catalyst Systems**

Several vendors were contacted for capital and operating-related costs for CO oxidation catalysts. The following general information was requested:

1) What is the cost range of the catalyst material?
2) Would this number change in considering three flow ranges, i.e., small, medium, and large, starting with a minimum flow of 100 Mlbs/hour and ending with ~3000 Mlbs/hour?
3) What operating temperature ranges with respect to high CO removal/oxidation are recommended?
4) What happens during start-up and low load operation? What would be the result of a prolonged operation with gas turbine exhaust temperatures of ~500^{o}F?
5) What are recommended space requirements and would flow straightening equipment be necessary?
6) What is the cost of reactor housing, required steel support, foundation needs and ductwork?

Cost information for CO oxidation catalysts was received from Engelhard, a catalyst vendor, and Nooter/Eriksen, a heat recovery steam generator (HRSG) vendor. Generalized estimates were also received for costs associated with increased pressure drops and retrofit applications. The information received is summarized below.

Engelhard

Engelhard CO catalysts are manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. The individual modules are installed within the support frame. The modules typically weigh approximately 50 lb. each. The number of modules required increases with gas flow. Substrate depth and corrugation patterns can vary depending on project requirements. Typically, performance is warranted for 2 to 3 years with an expected life of 5 to 7 years. Typical guarantees are based on a ±15% gas velocity profile distribution. The catalyst is not a hazardous material and in most cases can be recycled to reclaim the precious metals. Engelhard can also provide catalysts on a ceramic substrate.

Engelhard provided costs for a simple cycle turbine installation (catalyst at turbine discharge temperature) for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec. These costs were based on an oxidation catalyst that would achieve 90% CO conversion efficiency and 1" pressure drop across the catalyst panels (not total system pressure drop). The costs provided include the cost of an internal support frame and catalyst modules only. These costs are shown in Table 1.

Table 1. CO Oxidation Catalyst Costs Provided by Engelhard

Turbine Exhaust Flow (lb/sec)	Turbine Exhaust Temperature (F)	Required Inside Liner Cross Section (sq. ft.)	Estimated Cost Catalyst + Frame[a]
28.4	1050	67	$140,000
41.0	819	90	$155,000
318.0	990	716	$600,000
658.0	998	1522	$1,100,000
812.0	975	1881	$1,450,000
984.0	1116	2388	$1,550,000

[a]Costs reflect mid-1998 figures.

Regression analysis on the cost data in Table 1 suggest there is a nearly linear relationship between catalyst cost and exhaust flow rate (r^2 = 0.993, when Catalyst cost = 1541.8*(lb/sec) +

102370). Therefore, in estimating catalyst costs for the model turbines, the capital cost of a CO catalyst and frame for a given exhaust flow rate can be calculated using this relationship.

Information was also provided by Engelhard in response to the questions posed concerning operating issues associated with operating CO oxidation catalysts. A graph showing that lower performance/conversion accompanies lower temperatures was supplied. Typically, the catalysts Engelhard provides for gas turbine installations are supplied to a Heat Recovery Steam Generator (HRSG) supplier. The CO catalyst is generally installed within a HRSG. Supplemental firing usually is performed to increase steam production and thus gas temperatures at the catalyst and conversion requirements can be impacted by supplemental firing. Engelhard typically meets given HRSG cross section and maximum specified pressure drop allowed.

Engelhard indicated that reasonable retrofit estimates could not be provided due to many site-specific requirements. Their scope includes an internal support frame and catalyst modules which are installed inside the HRSG housing and as such, issues including flow straightening, housing, foundations, etc., are handled by other vendors.

<u>Nooter/Eriksen</u>

Nooter/Eriksen has become virtually sole sourced to Engelhard's Camet catalyst for their oxidation catalysts and provided an estimate of $650,000 for a 60% CO oxidation catalyst (no support frame or casing) in a GE Frame 7F installation (3,500,000 lb/hr with a catalyst temperature of approximately 900°F). They indicated that the price variation is approximately linear with mass flow and would approximately double to achieve 90% conversion. They were unable to comment on HAP destruction. The CO catalyst is occasionally required to also oxidize volatile organic compounds (VOCs), in which cases the catalyst is generally effective with unsaturated VOCs only and the catalyst must be located in a higher temperature window.

For high CO oxidation (90%), a temperature range of approximately 700°F to 760°F is preferred. If VOC oxidation is also required, the temperature window generally increases to 950°F to 1,100°F. It was indicated that prolonged operation at 500°F will not generally harm an oxidation catalyst unless the combustion turbine is operating with a high soot concentration in the exhaust, although there is little oxidation activity at 500°F.

Concerning retrofit issues, it was indicated that new ductwork to redirect flow outside of the original flow path would probably have the effect of obsoleting the greater portion of the HRSG. Most catalyst system guarantees are based on even flow distribution (typically ±15% RMS of the mean) entering the catalyst. If flow distribution devices were not originally included with the HRSG, this could increase the overall HRSG pressure loss by 0.5" to 1.0" W.C.

Generalized Pressure Drop Costs
Installation of a catalyst system will increase the pressure drop experienced by the turbine exhaust flow. The additional pressure drop results in a decrease in turbine power output. If the turbine is not operating at full load, additional fuel can be burned to make up for the lost power (fuel penalty). The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a percentage heat rate increase per inch of pressure drop due to the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. An equation for the fuel penalty was provided by the Gas Research Institute, which is based on an anticipated heat rate increase of 0.105% per inch pressure drop, $2/MMBtu for natural gas, and a 9,000 Btu/hp-hr baseline.

If the unit is operating at full load, the loss in power cannot be regained by burning additional fuel and will result in a loss in electricity sales. The costs associated with the power loss depend on site-specific factors, such as value of lost product or capital and annual costs for equipment required to make up for the power loss. Information on the loss in annual sales at different selling prices for electrical power was provided to EPA by Dow Chemical Company. For a GE Frame 7 turbine, the annual cost (lost sales) per inch of water pressure drop may be estimated using the following relationship: Annual Cost ($/inch) = 1,160*Power Value ($/Mwh) + 100.

Generalized Retrofit Costs
Estimates for retrofit costs were provided to EPA by Dow Chemical Company. Site-specific factors can have a major impact on the cost of retrofitting a catalyst control system to an existing turbine installation. In general, the heat recovery unit (if one exists) must be altered, ductwork and piling supports must be added, and piping, electrical conduits, and wiring must be lengthened. Some turbine installations have enough space between the turbine exhaust and the heat recovery unit to add the catalyst system. In cases where space is very limited, the heat recovery unit might have to be removed and replaced with a new vertical style unit. Estimates were provided for retrofit costs for adding a catalyst system to an ABB Type 11 turbine (gas flow rate = 580 lb/sec). The retrofit costs totaled about $800,000, which included $100,000 for ductwork. The cost of down time must also be estimated. It is difficult to extrapolate from the costs provided for this unit since the complexity and cost associated with retrofit installations varies so much by site.

- **Other Catalytic Systems**

Cost information in the form of comparisons to SCR systems for NOX control were received for SCONOx and XONON. More detailed cost information is needed from each vendor before an accurate assessment can be made concerning the cost of using these systems in conjunction with the model turbines. The information provided on these two systems is summarized below.

SCONOx™
Cost information for SCONOx was submitted by Goal Line Environmental Technologies LLC. The information consisted of a cost comparison model between SCONOx and SCR (selective catalytic reduction). The comparison is difficult to use for HAPs since it was based on NOX

control and therefore takes into account cost issues concerning ammonia use in the SCR system. The lifetime cost (10 years) for the reduction of NOX from 20 ppm to 2.5 ppm for a typical 270 MW plant was estimated as $12,970,970 for the SCONOx system and $17,882,560 for an SCR system. This analysis would need to be significantly adapted to be used constructively in model turbine cost analyses.

XONON

A cost comparison of the XONON system was provided by Catalytica Combustion Systems. The comparison consisted of estimates for DLN (dry low NOX), DLN + SCR (selective catalytic reduction), and XONON for controlling NOX from two different turbine models. As with the SCONOx information, the use of ammonia is a cost consideration that needs to be excluded when considering the cost of the XONON system.

Lean pre-mix (LPM) Combustors

Cost information for lean pre-mix combustors was taken from the "Alternative Control Techniques Document -- NOX Emissions from Stationary Gas Turbines" (ACT). The incremental capital costs for LPM units relative to diffusion flame units are provided for eight turbines in the ACT. A regression formula was developed where the incremental capital cost is a function of turbine rating (MW). This relationship is as follows:

Incremental capital cost (1990$) = 21454.3*MW + 408431; $r^2 = 0.981$

It is not expected that the maintenance requirements for an LPM unit will be different than for a standard design; therefore, the incremental capital cost is the only cost to be considered in calculating annual costs. According to the ACT, retrofit costs are 40 to 60 percent greater than new installation costs.