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AIR QUALITY AS A CONSTRAINT TO THE USE OF COAL IN CALIFORNIA

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ABSTRACT

Considering the air quality problems which exist in California without the combustion of coal for electric power generation, many have felt that any significant use of coal in the state would be inconceivable. However, recent developments in emission control technology have made it possible to burn coal in certain applications with significantly lower emissions than currently result from the use of fuel oil.

Low-NOx burners, wet scrubbing systems, baghouses and ammonia injection systems are feasible for use on large combustion sources such as utility boilers. These devices, used in combination with coal handling techniques which minimize fugitive dust and coal transportation related emissions, should enable new power plants and large industrial boilers to burn coal without the adverse air quality impacts for which coal has become notorious.

I. INTRODUCTION

Although coal has long been recognized as the most significant fossil fuel energy resource in the United States, it was not until after the Arab oil embargo of 1973 that oil and gas began to be considered as unacceptable fuels for use in large, fuel-intensive facilities such as utility boilers. Prior to the embargo, the federal government, through the Environmental Protection Agency, actually encouraged the conversion of coal-fired utility boilers to oil-fired operations as a relatively inexpensive technique for achieving substantial emission reductions.

Air Quality problems have been a significant factor affecting the design of power plants within the state and throughout California power plants have generally burned natural gas to the maximum extent possible. The use of fuel oil is limited by the South Coast Air Quality Management District (SCAQMD) to fuels containing no more than 0.25 percent sulfur. Other metropolitan APCD's limit the sulfur content of fuel oil to 0.5 percent.

Despite the fact that large coal-fired combustion sources have been considered to be generally unacceptable in California, it is now clearly imprudent to plan for the use of oil or gas in any new, baseload power plants. The principal options left for California for balancing the electric power supply and demand are conservation, cogeneration, hydro, geothermal, nuclear, and coal. The California Air Resources Board (ARB) has not taken a position regarding the construction of new hydro or nuclear power plants since the principal environmental risks associated with these facilities are outside the purview of the ARB and have therefore not been evaluated. Of the remainder, conservation (including decentralized solar), cogeneration and geothermal are viewed as generally preferable. However, to the extent that these alternatives are not available to satisfy electric power demand in California, the carefully regulated use of coal can be acceptable from an air quality perspective.

II. CALIFORNIA AIR QUALITY

Basin-like topography, frequent atmospheric temperature inversions and a high concentration of vehicles and industry have caused serious air pollution problems in California's three largest metropolitan areas and in the San Joaquin Valley. None of the state's fourteen air basins, shown in Figure 1, are currently free from violations of at least one ambient air quality standard. The ambient air quality standards which are related to the combustion of fossil fuels are shown in Table 1.

Table 2 summarizes the highest pollutant concentrations recorded during 1977. Oxidant (primarily ozone), a substance formed during a photochemical reaction between hydrocarbon emissions and oxides of nitrogen emissions, is the most pervasive air pollutant in California. As has always been the case, the highest oxidant level was recorded in the South Coast Air Basin. The basin with next highest oxidant concentration was the Southeast Desert, where the South Coast Air Basin air mass is transported by the prevailing west-to-east wind flow. Peak oxidant levels in the South Central Coast and San Diego Air Basins can also be affected by South Coast Air Basin emissions. However, the air quality problems in both of these basins are substantially affected by locally generated emissions. Although oxidant standard violations were recorded in each basin where measurements were made, the violations which have occurred downwind of major urban areas may be eliminated through the control measures applied in the urban areas provided adequate NOx control is achieved.

High Total Suspended Particulate matter (TSP) levels are caused by any or all of three different conditions: (1) Industrial sources of particulate emissions which are not equipped with adequate controls, (2) vehicular and industrial sources whose emissions of hydrocarbons, nitrogen oxides, and sulfur oxides are chemically transformed into "secondary" particulates such as organic aerosol, nitrate and sulfate, and (3) windblown dust. Within big air basins with high oxidant levels such as the South Coast Air Basin and the San Joaquin Valley Air Basin, secondary particulate is a very major problem.

In many rural areas windblown dust is the major problem. The adverse health effects of windblown dust, because of its large particle sizes, are generally far less significant than for equal concentrations of anthropogenic particulate emissions of either the direct or "secondary" variety. For this reason and for the practical problems associated with the control of windblown dust, the EPA does not consider levels in excess of the ambient air quality standards to be violations if they are caused by windblown dust.

SO_2 and sulfate concentrations are a serious problem in both the South Coast and San Joaquin Valley Air Basins. The South Central Coast and the San Diego County Air Basins have also experienced violations of the standard for sulfate. No other basins have been determined to have problems at this time.

Violation of the ambient air quality standard for nitrogen dioxide were recorded in the South Coast, South Central Coast, Southeast Desert, San Diego, and San Francisco Bay Area air basins. As has historically been the case, the NO_2 levels recorded in the South Coast Air Basin were almost double those recorded elsewhere.

In summary, California's fourteen air basins can be segregated into three categories from an air quality perspective considering only those pollutants significantly related to the combustion of fossil fuels.*

Six basins, South Coast, South Central Coast, San Diego, San Francisco Bay Area, San Joaquin Valley and the Sacramento Valley, experience numerous and severe violations of ambient air quality standards due to both locally generated and transport related emissions. Two basins, Lake Tahoe and the North Central Coast, experience less frequent and less severe violations, which appear to be primarily the result of locally generated emissions. Six other basins, Southeast Desert, Mountain Counties, Great Basin Valleys, North Coast, Northeast Plateau and Lake County, experience varying levels of air pollution, the highest of which, however, are related to emissions from upwind areas or rural fugitive dust.

*Certain of the California air basins experience pollution problems which are not related to fossil fuel combustion. The Lake County and North Coast Air Basins, for example, are experiencing substantial violations of the state's ambient air quality standard for hydrogen sulfide due to the currently inadequately controlled generation of electric power from geothermal steam.

III. FUTURE AIR QUALITY

Despite the historical persistence of of air quality problems in California, two factors now allow a modicum of optimism regarding future air quality levels. For the first time in history, it is no longer permissible to build major new sources of air pollution, which will exacerbate violations of ambient air quality standards. The Clean Air Act Amendments of 1977 clearly articulate a federal policy of prohibiting the construction of sources of air pollution, which will contribute to existing air quality problems even though these sources may be substantially lower in emissions than similar, existing sources. The fact that a proposed new source has relatively low emissions has in the past been considered an adequate justification for its construction. Federal law now recognizes the obvious fact that degraded public health and welfare are the result of adding "clean" new sources to an overburdened air shed just as increased risks are associated with adding lighweight cargo to an overloaded boat. The federal New Source Review (NSR) program requires that mitigation measures or "trade-offs" sufficient to offset the adverse impact of any major new source of air pollution be a part of new industrial projects. The existence of the federal NSR requirements allows air pollution control agencies to concentrate on existing air problems instead of being forced to deal with unrestrained increases in emissions.

The second factor which is now contributing to a solution to the state's problems is the increased focus on control strategy development at the state and federal level. Historically, local air pollution control agencies have been forced to regulate industrial sources of air pollution with little assistance. The state and, to a lesser extent, the federal government are now recognizing the gross inefficiency associated with requiring local agencies to independently develop and implement regulations for the control of industrial air pollution problems of state-wide or national impact. The basic control strategies needed to reduce emissions from most types of sources are identical whether the source is located in Los Angeles, San Francisco, Bakersfield or Houston. A single control strategy developed at the state or federal level as "model rules" can be given to the numerous local districts for adoption. These "model rules" can be tailored prior to adoption to the needs of individual districts.

Although the U.S. Environmental Protection Agency is not yet pursuing the model rule concept, EPA does provide "guideline documents" which contain useful information on the emissions control potential for various categories of industrial sources. The guideline documents, useful in developing emission control regulations for both new and existing sources, are supplemented by New Source Performance Standards (NSPS). However, as discussed in greater detail below, the EPA NSPS are usually set at levels which require far less emission control than is technologically feasible and economically reasonable.

A detailed analysis of the emission control measures needed to achieve and maintain the ambient air quality standards throughout California is currently being developed through the combined efforts of the ARB, local governments, and private organizations involved in the Air Quality Maintenance Planning process, which is mandated by the Clean Air Act. The paragraphs which follow give a very brief and general overview of the emerging plans which are expected to be published early in 1979 as the State Implementation Plan (SIP).

The prospects for achieving and attaining the ambient air quality standards in the 1980's are excellent for most of California's basins. Although substantial SO_2, NOx and particulate matter emission increases could be associated with the shift from natural gas to fuel oil, which is now occurring, work now underway at the ARB indicates that these emissions from major combustion sources can be dramatically reduced through the use of further fuel desulfurization or stack gas scrubbing for SO_2 and particulate emission control, ammonia injection systems for NOx control, and fabric filtration (baghouses) for particulate control. A recent ARB staff report[1] describes how the use of certain of these control techniques applied to thermally enhanced oil recovery operations in the San Joaquin Valley can provide essentially all of the SO_2 control projected to be needed to attain the ambient air quality standards for SO_2 and sulfate and more than half of the NOx control needed to achieve the oxidant standard through a combination of hydrocarbon and NOx control. A draft Air Quality Maintenance Plan[2] prepared by the Association of Bay Area Governments outlines the type of hydrocarbon controls which appear to be available to cause attainment for oxidant in the nine counties of the San Francisco Bay Area. Similar controls applied in the South Central Coast, San Diego, North Central Coast and Lake Tahoe air basins may be sufficient to achieve and maintain the oxidant standard provided growth is carefully managed. Air basins which are experiencing oxidant violations as a result of long-range transport may achieve attainment status provided most feasible hydrocarbon control measures are integrated with appropriate NOx emission controls in upwind areas.

No plan has yet been developed which indicates that the oxidant standard can be achieved in the South Coast Air Basin without economically infeasible control approaches involving the curtailment of current vehicular and industrial activities. However, substantial improvement is already possible and attainment of the standard for NO_2 appears feasible through the NOx reductions expected from the motor vehicle emission standards adopted for future years in combination with the use of ammonia injection systems on large combustion sources and some control of other sources.[3] Attainment of the SO_2 and sulfate standards appears to be possible through the application of substantially increased fuel oil, diesel oil, and gasoline desulfurization in combination with control measures on coke calcining kilns, refinery FCC units, and other such sources.[4]

IV. ACCOMMODATION OF COAL IN CALIFORNIA

In areas of California which are projected to achieve and maintain the ambient air quality standards through the implementation of the plans now under development, it will be possible to permit the construction of major new facilities such as coal-fired power plants provided the emissions from such projects are not so great as to cause violations of the standards. If the emissions expected from a coal-fired power plant are calculated to cause an air quality violation, trade-off measures may enable the adverse impact to be mitigated. The need for trade-offs will therefore depend on whether the local air pollution strategy provides for an increment of emissions growth without causing ambient air quality standard violations.

Mitigation measures could also be required if the proposed facility would lead to unacceptable air quality degradation in Prevention of Significant Deterioration (PSD) areas or Air Conservation Areas (ACA's) located downwind. The State's Air Conservation Program[5], currently under development, is directed at maintaining superior air quality levels (cleaner than required by ambient air quality standards) in areas of important aesthetic significance (e.g. Yosemite, Redwoods National Park, etc.).

The ability for coal-fired power plant proponents to develop emission "trade-off" measures, when necessary, will depend on the quantity of emissions to be offset and the availability of such trade-offs in the vicinity of the proposed new project. Except for the Greater Metropolitan Los Angeles area, it appears that a substantial quantity of trade-offs will be available from existing power plants. At this time, it appears all feasible power plant emission control measures may not be required to achieve and maintain the ambient air quality standards through most of California. Where all feasible controls are not required, it may be possible for new power plants to be constructed without an increase in electric-power-related emissions through the retrofitting of SO_2, NOx and particulate matter emission controls to existing oil-fired power plants provided that the emissions from the proposed new facility do not exceed the emission reduction potential from existing power plants. In certain areas, however, no trade-offs may be required.

V. EMISSION CONTROL FEASIBILITY

Uncontrolled Emissions - The popular conception regarding the high emission levels associated with coal is born out by a comparison of the "uncontrolled" emissions from coal combustion compared to the combustion of oil and natural gas. As shown in Table 3, NOx, SOx and particulate emissions from coal combustion are substantially greater than from either oil or gas with the particulate emissions from coal exceeding the particulate emissions from oil by a factor of 105 when the oil burned has a sulfur content of 0.5 percent by weight.

The reason for the significant differences between the emissions created from the combustion of coal and other fossil fuels is primarily due to differences in their composition. A typical western coal is 71.43 percent by weight carbon, 1.36 percent by weight nitrogen, 1.00 percent by weight sulfur, 5.05 percent by weight hydrogen, and 8.42 percent by weight ash made up of silica, trace metals and other noncombustible materials. The nitrogen contained in the coal is a contributor to the NOx emission produced during combustion. The ash is the principal source of particulate emissions. While fuel oil may contain as much sulfur as coal, it typically contains only 0.50 percent by weight nitrogen and 0.04 percent by weight noncombustible impurities. Natural gas is typically almost entirely made of methane (93.33 percent by volume and contains only trace quantities of nonhydrocarbon components, such as 0.0009 percent by weight hydrogen sulfide (H_2S), the combustion of which creates the relatively low concentration of SO_2 emissions associated with natural gas combustion. NOx emissions from gas-fired combustion are only created from the reaction between the nitrogen and oxygen contained in the combustion air. No fuel bound nitrogen is present to contribute to the formation of NOx.

Particulate Emission Controls - Since the particulate emissions from uncontrolled coal combustion are great enough to create a substantial public nuisance, there have been particulate matter controls applied to coal-fired power plants for quite some time. The most common control device is the electrostatic precipitator (ESP), which removes combustion particulates by ducting the stack gases between charged plates. The electrostatic charge applied to the particles results in their migration to the plates where they periodically drop into a collection hopper each time the plates are "rapped" to shake the particles free.

The effectiveness of electrostatic precipitators depends on the surface area of charged plates, particle size, and particle resistivity. While ESPs can be designed for removal efficiencies exceeding 99%, the collection plate area required, and therefore the system cost, increases rapidly above 95% removal efficiency.

Fabric filtration is an alternative to the use of electrostatic precipitators which makes substantially increased particulate emission control feasible. As shown schematically in Figure 2, a baghouse consists of an enclosure containing numerous cylindrical fabric filters ("bags") through which all of the combustion gases are ducted. Sufficient filter area is provided to red[illegible] pressure drop through the baghouse to [illegible]-5 inches of water on typical coal-fi[illegible]d utility boiler applications.[6] To [illegible]btain a combination of high filtration [illegible]fficiency and low pressure drop, more [illegible]han 10,000 individual bags might be used [illegible] a 500 megawatt coal-fired boiler.

In tests run on full scale coal-fired boilers using fabric filtration, particulate removal efficiencies of 99.84% and 99.91% have been reported[6]. The resultant stack emissions with such efficiencies were recorded at .01 and .005 pounds per million BTU heat input.

SO_2 Emission Controls - Stack gas scrubbing for sulfur dioxide removal has been developed to the point where 95% efficiency can be routinely achieved.[7] The latest experience in Japan indicates that the reliability of scrubbing systems has been improved to the point where the scrubber is "available" more than 99% of the time.[7]

A number of regenerable and nonregenerable, or "throw away", systems are on the market. A schematic of a simple nonregenerable system incorporating the use of a limestone slurry is shown in Figure 3.

The SO_2 removal mechanism for this type of scrubber involves a reaction between SO_2 and $CaCO_3$ to form a precipitate of $CaSO_3$, [illegible] removed from the system as [illegible] [illegible]able systems, such as the [illegible] [illegible]lthough more expen[illegible] [illegible]bsorbent, produce a byproduct, such as sulfuric acid, and have no solid waste.

NOx Emission Controls - The control of NOx emissions from fossil fuel combustion can be achieved through the use of combustion modifications and stack gas treatment. Uncontrolled NOx emissions from coal combustion have been reduced below 200 ppm through burner and furnace modifications in experimental work.[8] Combustion modifications applied to the Isogo Power Station operated by the Electric Power Development Company of Japan have resulted in emissions averaging 250 ppm on 265 MW furnaces in daily operation.[7] Emissions at the Isogo facility were reduced from 669 ppm to 576 ppm level through the use of NOx ports, and from 576 ppm to 240 ppm through the use of low-NOx burners.

The greatest potential for minimizing the NOx emissions associated with coal combustion is through the use of ammonia injection. Two basic processes, one of which involves the catalytic enhancement of the NOx elimination, have been developed. Both rely on the basic reactions shown below:

$$NH_3 + 1/4\ O_2 \longrightarrow NH_2 + 1/2\ H_2O \quad (1)$$

$$NH_2 + NO \longrightarrow N_2 + H_2O \quad (2)$$

The ammonia is consumed in the process with the nitrogen and hydrogen atoms being converted to water and nitrogen gas when reacted with oxygen and nitric oxide. This reaction will take place without catalytic enhancement if ammonia is injected into the exhaust gas at a temperature of approximately 1750 F. The temperature required for the reaction can be reduced through the addition of hydrogen. The noncatalytic ammonia reduction of nitric oxide has the disadvantages of lower efficiency than catalytic and a narrow temperature window, which implies control difficulties.

The noncatalytic or "thermal" ammonia injection process has been shown to be relatively insensitive to fuel properties in numerous tests, some of which involved coal combustion. The noncatalytic system is shown schematically in Figure 4.

Catalytically enhanced ammonia injection systems offer the advantages of higher NO removal efficiency, lower reaction temperature, and a broad temperature window. The catalytic system, shown schematically in Figure 5, has achieved greater than 90% NO removal in several applications[7]. A pilot catalytic ammonia injection system installed at the Isogo Power Station has achieved 90% NO removal on exhaust gas from coal combustion. Catalyst fouling with combustion particulate, a problem in earlier installations using "dirty" fuels, has not presented problems at Isogo, which uses plate-type as opposed to pelletized catalysts. The open channels of the plate-type catalyst are less susceptible to particulate matter fouling. Hot-side electrostatic precipitators provide an alternative approach to reducing potential particulate fouling problems, but the experience at Isogo indicates that they may not be required.

A characteristic of both catalytic and noncatalytic ammonia injection systems is the production of some ammonium bisulfite and ammonium bisulfate when high ammonia injection rates are used to maximize NO removal. The experience in Japan indicates, however, that ammonium bisulfite/bisulfate production does not produce significant problems since the deposits tend to form on air preheaters which can be periodically cleaned by water washing or soot blowing.

Emission Standards Achievable - Table 4 summarizes the currently applicable emission standards for coal-fired power plants and the levels of control which have been achieved on various facilities. Note that the current EPA New Source Performance Standards (NSPS) for both coal-fired and oil-fired power plants allow for substantially greater emissions than have been proven to be achievable at certain existing power plants.

NOx emissions of 0.34 lbs/10^6 BTU have been demonstrated at the Isogo Power Station in Japan without stack gas controls and 0.034 lbs/10^6 BTU has been achieved with the ammonia injection pilot plant. The level of NOx control reflecting "best available control technology" appears to lie between 0.04 and 0.15 lbs/10^6 BTU depending on whether catalyst durability on coal proves acceptable from an economic perspective. The 0.15 level appears to be achievable with the use of the noncatalytic process.

SOx emissions of 0.05 lbs/10^6 BTU represents 95% control over the emissions of coal with a sulfur content of 1%. Most western coals are significantly below this level of sulfur content.

Particulate matter emissions of .005-.01 lbs/10^6 BTU have already been achieved at two coal-fired facilities which incorporate fabric filtration. Given the increased particulate removal efficiency associated with stack gas scrubbing, it appears as though a standard of 0.005 can be achieved.

For comparison purposes, Table 4 includes emissions data from Alamitos #5, an oil-fired power plant operated by Southern California Edison which is the cleanest oil-fired power plant in California, and Scattergood #3, a natural gas-fired power pland operated by the Los Angeles Department of Water and Power which is the cleanest fossil fuel-fired power plant in the state. Comparing the aggregated NOx SOx and particulate emissions from

Alamitos #5 to the author's proposed best available control technology standards for coal, it is seen that Alamitos #5 could have as much as 500% greater emissions than a modern coal-fired power plant of equivalent output.

Control System Costs - A wide range of cost estimates have been made for the various emission control systems applicable to coal-fired power plants. Shown in Table 5 are the author's estimates for control system costs compared to basic power plant costs based on data from a variety of sources. Scrubbers, non-catalytic ammonia injection and electrostatic precipitators are estimated to account for 27% of the cost associated with producing electricity at the "busbar". Such control costs account for much less than 27% of the consumer cost of electric power since administrative costs and the costs associated with electric power transmission have not been included.

VI. SUMMARY AND CONCLUSIONS

The state of the art in emission control has progressed to the point where coal can be used to produce electricity with less air pollution than is currently associated with electricity produced from the combustion of low sulfur fuel oil. Progress, now being made in the development of a new plan for achieving and maintaining the ambient air quality standards in California, indicates that new emission sources can be accommodated provided they do not have emissions which will cause violations. Preliminary air quality modeling indicates that if emissions from coal-fired power plants are controlled to the levels indicated as feasible above, then the localized air quality standard violations can be avoided.

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6. U.S. EPA, Environmental Research Information Center, Fabric Fitter Particulate Control on Coal-Fired Utility Boilers: Nucla, Co. and Sanbury Pa., EPA 625/2-77-013.

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Table 1 - Ambient Air Quality Standards Significantly Affected by Fossil Fuel Combustion

Pollutant	State Standards	Federal Standards	Precursors
Nitrogen Dioxide (NO_2)	.25 ppm hrly avg	.05 ppm annual avg	Nitrogen Oxide (NO)
Sulfur Dioxide (SO_2)	.05 ppm 24 hr avg .5 ppm hrly avg	.14 ppm 24 hr avg .03 ppm annual avg	Sulfur Dioxide
Total Suspended Particulate Matter (TSP)	60 $\mu g/m^3$ annual avg 100 $\mu g/m^3$ 24 hr avg	75 $\mu g/m^3$ annual avg 260 $\mu g/m^3$ 24 hr avg	Particulates, sulfur oxides, nitrogen oxides, hydrocarbons
Sulfates	25 $\mu g/m^3$ 24 hr avg	None	Sulfur dioxide
Oxidant (O_3)	.10 ppm hrly avg	.08 ppm hrly avg	Hydrocarbons (HC), Nitrogen oxide
Visibility	10 miles when humidity is less than 70%	None	Particulates, Sulfur dioxides, Nitrogen dioxides, Hydrocarbons

Table 2 - Maximum Pollutant Concentrations, 1977

Basin	Oxidant (one hour - ppm)	TSP (24 hour- $\mu g/m^3$)	SO_2 (24 hour- ppm)	Sulfates (24-hour- $\mu g/m^3$)	NO_2 (one hour- ppm)
1. South Coast	.39*	508*	.132*	64.7*	.69*
2. South Central Coast	.26*	293*	.035	27.5*	.30*
3. San Diego	.25*	240*	.023	37.9*	.36*
4. San Francisco Bay Area	.17*	179*	.090	19.4	.26*
5. San Joaquin Valley	.21*	793*	.092*	73.7*	.18
6. Sacramento Valley	.19*	250*	.014	6.6	.17
7. North Central Coast	.14*	166*	.053	7.6	.12
8. Lake Tahoe	10*	98	0	-	.09
9. Southeast Desert	.27*	732*	.088@	18.6	.26*
10. Mountain Counties	.10*	72	-	2.2	-
11. Great Basin Valleys	-	-	-	-	-
12. North Coast	-	218*	-	13.1	-
13. Northeast Plateau	-	215*	-	18.6	-
14. Lake County	-	182*	.01#	3.9	-

* Indicates level in excess of state or federal ambient standard

\- Indicates data not available

\# Total sulfur

@ Combination standard - Ox/SO_2 exceeded on another day when SO_2 .076 & Ox = .10

Table 3 - Comparison of Emissions from a Coal-Fired, Oil-Fired, and Gas-Fired 450 MW Power Plant Without Stack Gas Controls (Pounds per 10^6 Btu)

Pollutant	Coal-Fired[a]	Oil-Fired[b]	Gas-Fired
NOx	0.45	0.17	0.11
SOx	1.33	0.52	nil
PM	4.20	0.04	nil

Notes: [a] Based on burning 1% sulfur coal
[b] Based on burning 0.5% sulfur oil

Table 4 - Controlled Power Plant Emissions Comparison

	Emissions, lbs/10^6 Btu heat input		
	NOx	SOx	PM
EPA NSPS, (oil)	0.3	0.8	.1
EPA NSPS, (coal)	0.7	1.2	.1
ISOGO Power Station (coal)	0.34	0.02-0.1	.035
ISOGO NH_3 Injection Pilot Plant	0.034	-	.035
Colorado Ute Nucla Plant (coal)	-	-	.01
Pennsylvania Power and Light Sanbury Plant (coal)	-	-	.005
Author's Proposed BACT (coal)	0.04-.15	0.05	0.005
Alamitos #5 (0.25% oil)	0.17	0.26	0.049
Scattergood #3 (gas)	0.034	0.0008	0.0025

Table 5 - Estimated Costs Associated with Electricity from Coal

	Capital Cost $/KW	Electricity Cost Mills/KWHR	Percent of Total Electricity Cost
Basic Power Plant	600	11	42
Scrubbers	110	3	11.5
Electrostatic Precipitators	35	1	4
Non-Catalytic Ammonia Injection	12	3	11.5
Fuel Costs	Externalized	8	31
TOTAL	757	26	100

Figure 1 California air basins

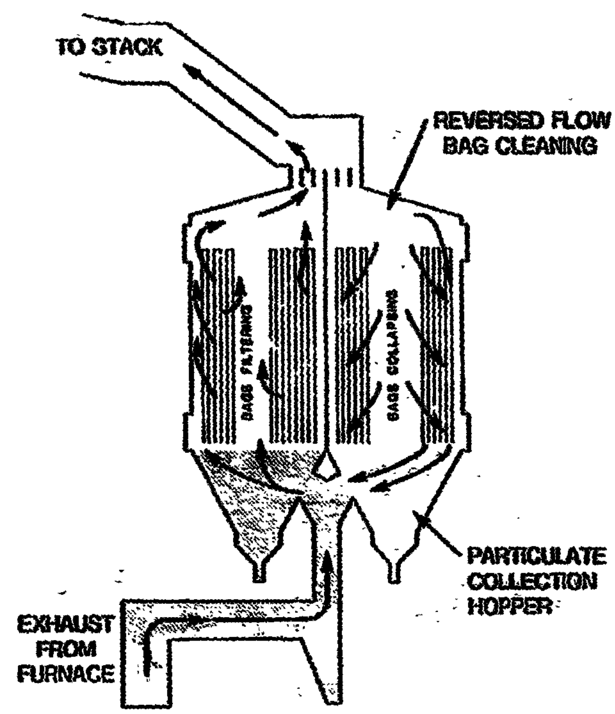

Figure 2. Fabric filtration (baghouse) system

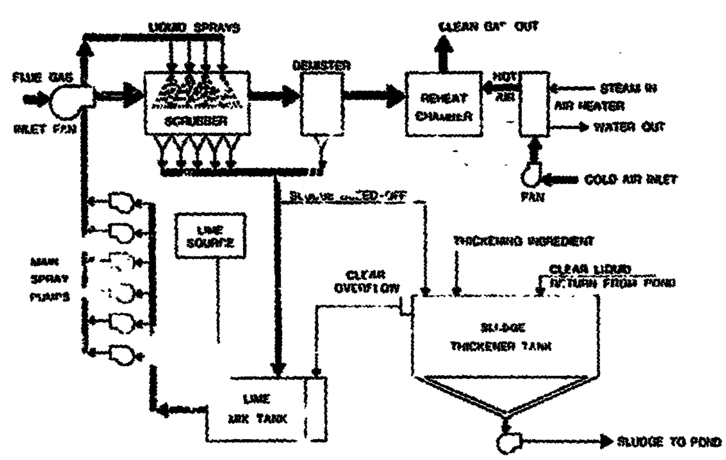

Figure 3. Limestone slurry flue gas desulfurization

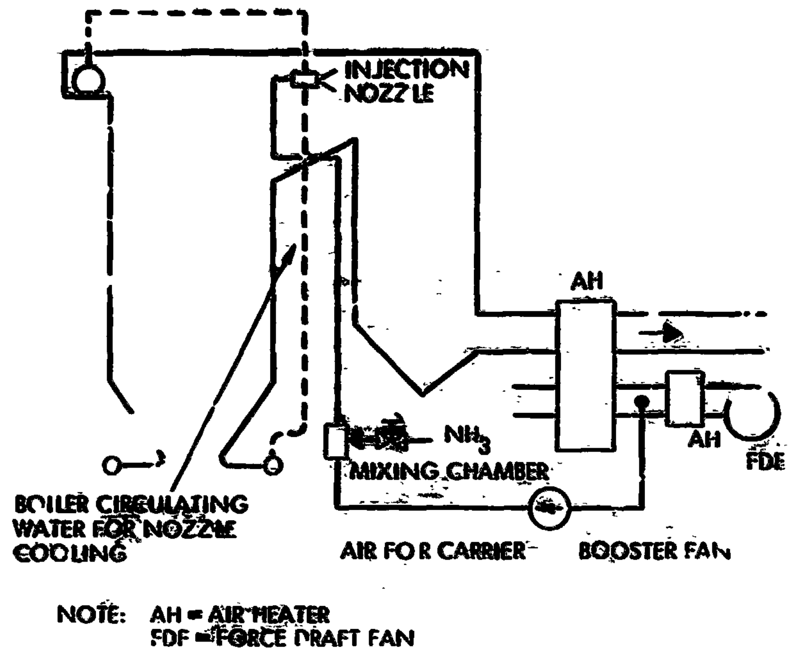

Figure 4. Noncatalytic ammonia injection system

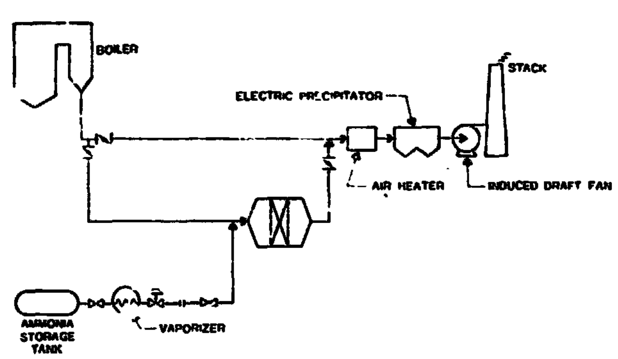

Figure 5. Catalytic Ammonia Injection System