Energy-Efficient Air Pollution Controls for Fossil-Fueled Plants

Technology Assessment

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ENERGY-EFFICIENT AIR POLLUTION CONTROLS FOR FOSSIL-FUELED PLANTS

INTRODUCTION

The 1990 Clean Air Act Amendments (CAAA) require most fossil-fuel fired power plants to reduce sulfur dioxide, nitrogen oxides, and particulate emissions. While emission-control equipment is available to help most of New York State's 91 utility units in 31 power plants comply with the new regulations, the technologies currently available consume significant amounts of energy, increase carbon dioxide emissions relative to a particular plant's output, reduce a plant's operating efficiency, and may produce large amounts of solid and/or semisolid byproducts that use additional energy for processing and disposal.

This report:

- Describes several pollution-control technologies that are more energy efficient compared to traditional technologies for controlling sulfur dioxide, nitrogen oxide, and particulates, that may have application in New York State. These technologies are either in commercial use, under development, or in the demonstration phase;
- Presents operating characteristics for these technologies; and
- Discusses solutions to dispose of pollution-control system byproducts.

Estimated energy consumption for emission-control systems relative to a plant's gross generating capacity is:

- 3 to 5 percent for reducing up to 90 percent sulfur dioxide emissions from coal-fired plants;[1,2]
- 0.5 to 2.5 percent for reducing nitrogen oxide emissions by up to 80 percent from all fossil-fuel fired plants;[3] and
- 0.5 to 1.5 percent for controlling particulate emissions from oil- and coal-fired plants.[4,5]

While fuel switching and/or cofiring with natural gas are options to reduce emissions, these techniques are not considered in this report; the discussion is limited to fossil-fueled steam-generating plants.

TECHNOLOGY

The CAAA were signed into law to reduce environmental impacts from many sources, including fossil fuel combustion. The most problematic combustion products are sulfur dioxide, nitrogen oxides, and solid particulate emissions. However, the environmental benefits associated with using technologies to minimize release of these combustion products to the atmosphere are offset by increased parasitic power requirements, reduced plant operating efficiency, increased carbon dioxide emissions, and the need to dispose of the emission-control system's byproducts.

Parasitic power includes power to overcome the additional pressure drop of the flue gas through the sulfur dioxide scrubber vessel, nitrogen oxides removal reactor, and/or particulate emission control device; the power to circulate and inject sulfur dioxide scrubber limestone slurry, to inject reagent for removing nitrogen oxides, and to energize particulate collection systems; and, the power to prepare reagents for injection into the flue gas.

The cumulative incremental parasitic power consumption by pollution-control equipment for limiting emissions of sulfur dioxide, nitrogen oxides, and particulates from coal-fired plants may be as high as nine percent of gross plant generation.[1,2,3,4,5]

A coal-fired plant producing 300 MW for distribution and sale must generate up to an additional 27 MW to provide power for pollution-control equipment. Making up for this lost generating capacity would raise rates and environmental impacts. If this incremental power for pollution-control equipment were generated by wind energy, a wind-power station encompassing two to three square miles would be needed.

For gas-fired plants, when nitrogen oxides are the major pollutants, about one percent of gross plant generation may be required for emission control.[3] An oil-fired plant's parasitic power consumption is higher compared to a gas-fired plant, but lower compared to a coal-fired plant if low-sulfur fuel oil is used to meet sulfur dioxide emission regulations. The net effect of this increased power consumption, for a given plant's output, is a reduction in the plant's generating efficiency of about one to four percent.[3,4,5]

In addition to reducing the plant's generating efficiency, pollution-control systems increase carbon dioxide emissions relative to a particular plant's generating output.

For coal-fired power plants, carbon dioxide emissions are on the order of 1.3 tons per MW hour.[6] Pollution-control equipment operation will produce an incremental 200,000 tons of increased carbon dioxide emissions annually from a 300-MW coal-fired, baseloaded plant, with a 0.65 service factor, due to required add-on sulfur dioxide, nitrogen oxides, and particulate pollution-control systems.[7]

For natural gas-fired steam-generating plants, carbon dioxide emissions are about 0.6 tons per MW hour. Add-on pollution-control systems for nitrogen oxides will add an incremental 10,000 tons of increased carbon dioxide emissions annually to the atmosphere.[6,8]

When pollutants from the flue gas of fossil-fuel fired boilers are removed, byproducts are produced that may be marketable or that will require disposal. For example, in removing sulfur dioxide from a boiler burning four percent sulfur coal using a wet-limestone scrubber with only settling for sludge dewatering, as much as 1200 pounds of waste material per ton of coal burned is produced.[9] These byproducts usually undergo additional processing to meet end-use specifications or disposal regulations.

Sulfur Dioxide Emission-Control Technology

Sulfur dioxide emissions are a major source

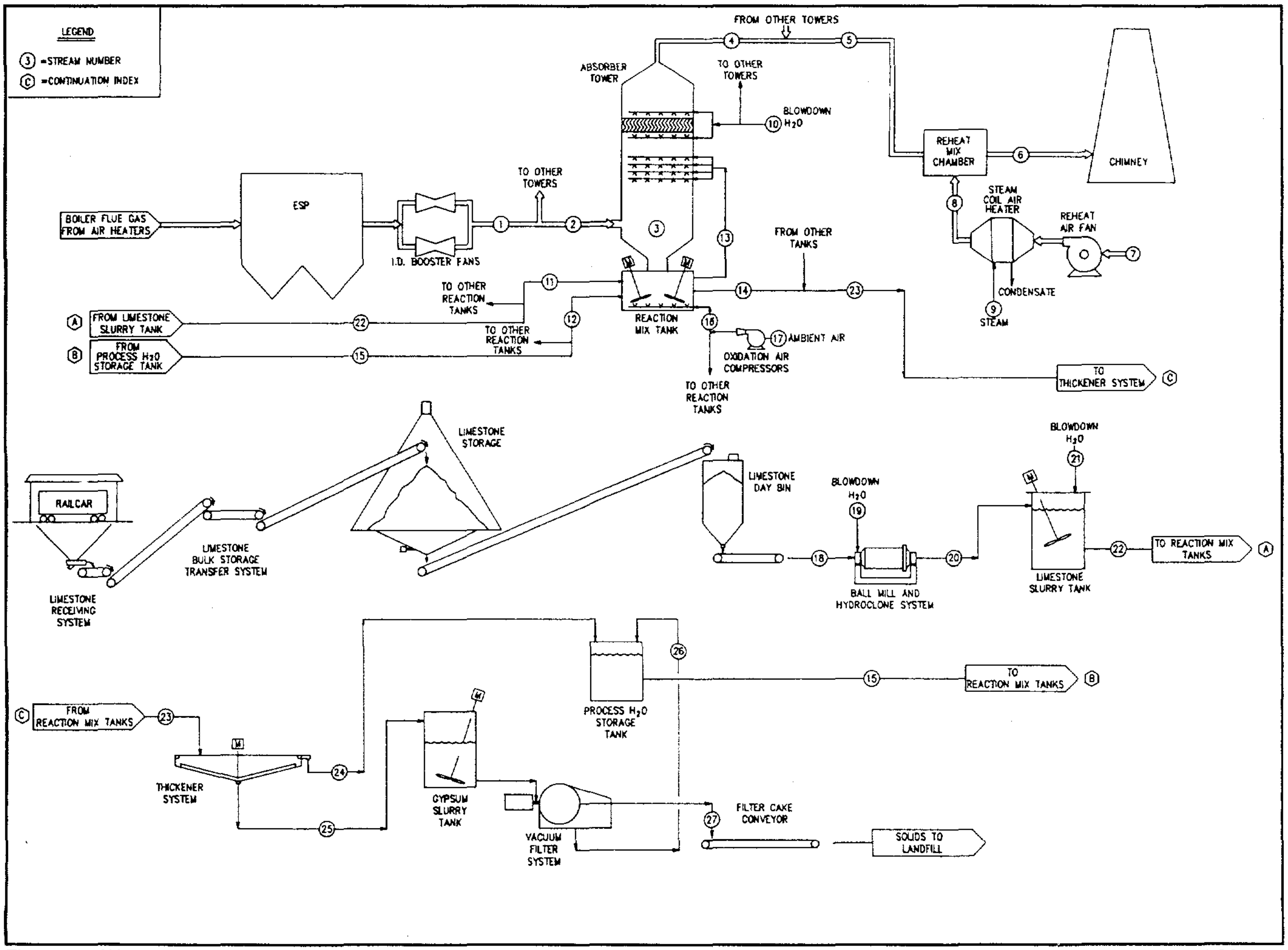

Figure 1. Wet Limestone FGD Process

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of acid rain. The CAAA calls for a nationwide annual sulfur dioxide emission reduction of 10 million tons, using 1980 baseline emissions, by 2000, in two phases.

Three coal-fired utility plants in New York State must reduce sulfur dioxide emissions under Phase 1 of the CAAA, effective January, 1995. Two oil-fired utility plants are also on the list targeted for Phase 1 sulfur dioxide reductions; however, these plants recently switched to fuel oil lower in sulfur, and are now in compliance. All coal- and oil-fired plants will be obligated to control sulfur-dioxide emissions below 1.2 pounds/million Btu heat input by 2000 under Phase 2 of the CAAA.

Utilities that consider switching to fuels lower in sulfur to meet emission regulations will probably have higher fuel costs and fewer competitive suppliers. An alternative to fuel switching is flue-gas scrubbing, which may be economical at some locations, to control sulfur dioxide emissions. Although domestically used with coal-fueled boilers, flue-gas scrubbing, as demonstrated in foreign installations, also can be applied to oil-fueled boilers.

Flue-gas scrubbing sulfur-dioxide-control systems generally include three types:

- Wet limestone with landfill disposal or upgrading a sludge or dewatered byproduct for commercial use;
- Dry lime that produces a dry byproduct for landfill disposal or commercial use; and
- Processes that regenerate and reuse scrubbing reagents to produce a concentrated sulfur dioxide, sulfuric acid, or elemental sulfur byproduct.

Some of these processes are briefly described in Appendix A.

The wet-limestone desulfurization process with sludge dewatering and landfill disposal shown in Figure 1, is the commercially proven, baseline scrubbing process. Many second-generation, energy-efficient processes of this type are under development or in the demonstration phase.

New York State Electric & Gas Corporation

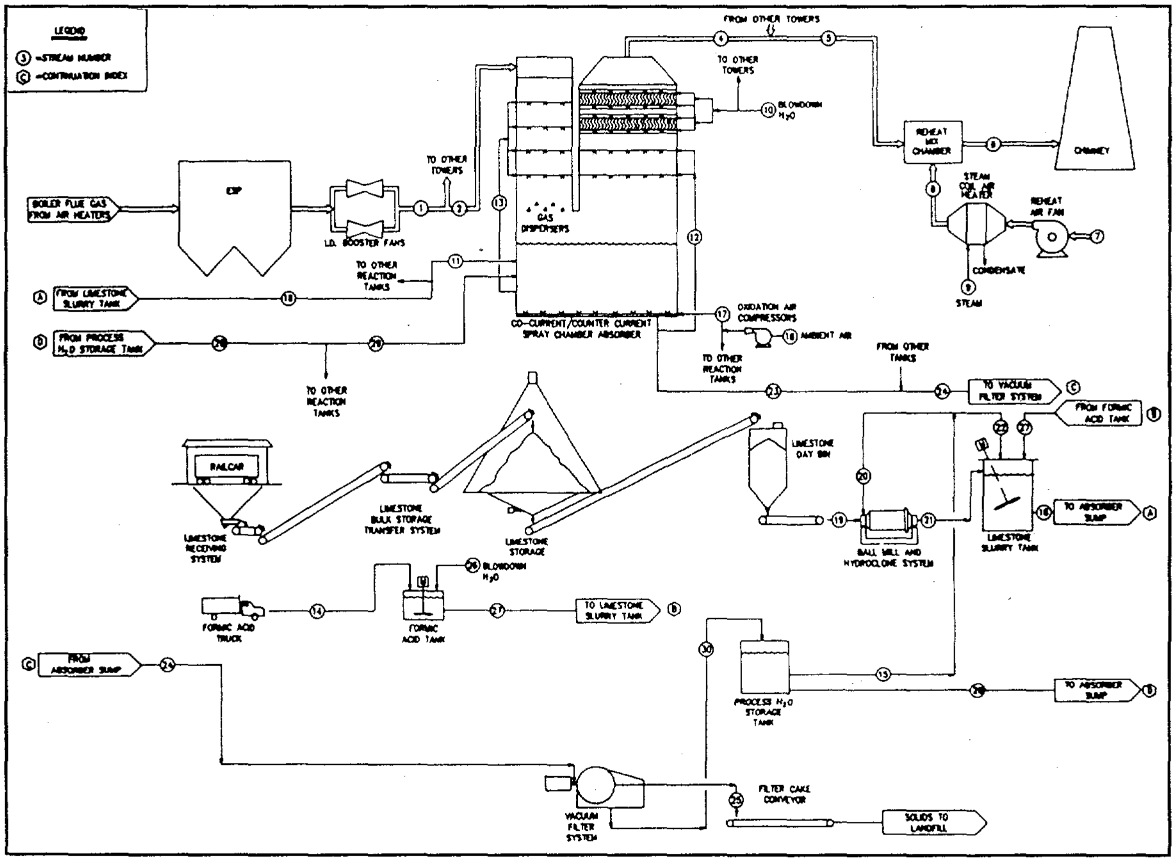

Figure 2. Saarberg-Holter FGD Process

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plans to install a Saarberg-Holter-Umwelttechnik wet-limestone system at the two-unit, 300 MW Milliken Station as part of the United States Department of Energy (DOE) Clean Coal Technology IV Program. This technology combines cocurrent/countercurrent scrubber design to improve flue-gas and limestone-slurry contacting. This innovative system will use organic acid additives to increase limestone reagent use and to suppress scale formation that could lead to operating problems. A split module open-spray tower absorber will be located at the base of a new flue-gas stack. The system includes equipment for producing marketable commercial-grade gypsum, calcium chloride, and fly ash to minimize solid-waste disposal. This space-saving sulfur dioxide scrubbing system is expected to reduce parasitic power consumption by one percent compared to the baseline wet limestone process.[10] For the 300-MW Milliken Station, a one percent reduction in parasitic power consumption is equivalent to three MW. A flow diagram of the process is shown in Figure 2.

The Chiyoda-Thoroughbred 121 (CT-121) process' jet-bubbling reactor/absorber design injects flue-gas below the surface of the limestone-reagent scrubbing slurry. Flue-gas/reagent-slurry contacting is enhanced in the jet-bubbling zone. While the pressure-drop across the absorber is higher compared to an open-spray tower, the design eliminates the need for energy-consuming slurry injection and recycle pumps. Moreover, sulfur dioxide absorption, sulfite oxidation, and gypsum precipitation occur in the scrubber vessel, eliminating the need for additional pumping capacity. The process produces large, readily dewatered gypsum crystals. Parasitic energy consumption is expected to be lower compared to conventional wet-limestone scrubbing. A flow diagram of the process is shown in Figure 3.

The Pure Air Process uses a co-current, downflow absorber with a single level of grid

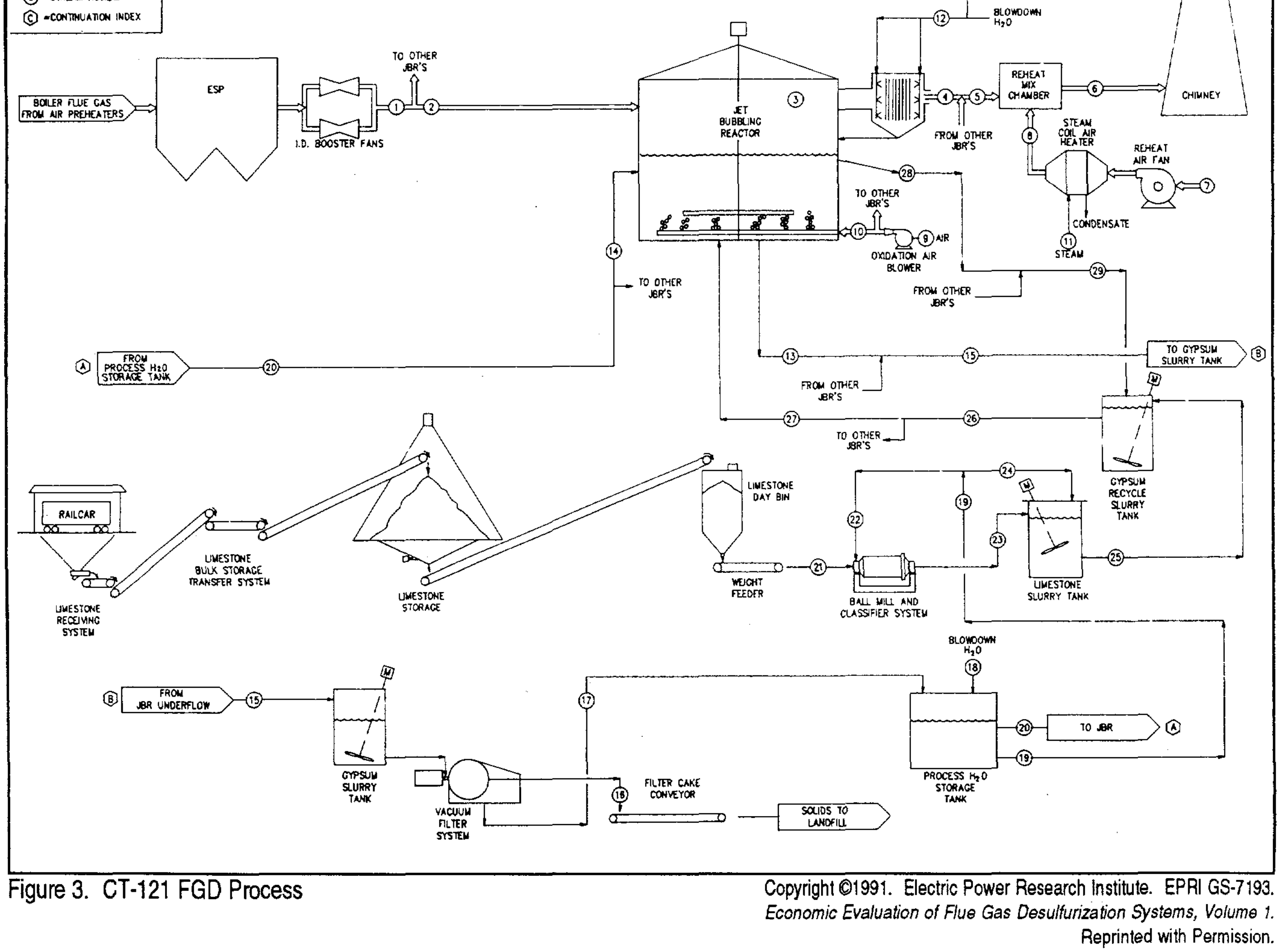

Figure 3. CT-121 FGD Process

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packing for contacting sulfur dioxide with limestone slurry. The co-current absorber permits higher gas velocities and therefore a compact design. Grid packing increases flue-gas/limestone slurry contacting, enhancing sulfur dioxide removal. An Air Rotary Sparger system at the base of the absorber provides slurry agitation and forced oxidation to produce a gypsum sludge for dewatering and disposal. Open-grid packing, scaling, and plugging problems are resolved by using additives. Parasitic energy is expected to be lower compared to conventional wet-limestone scrubbing. The flow diagram for the Pure Air Process is shown in Figure 4.

These three advanced, wet-limestone scrubbing systems illustrate how the penalties associated with sulfur dioxide removal can be substantially reduced. An alternative approach, dry-scrubbing technology, produces a solid waste that does not require dewatering, and is easier to dispose of. Most dry processes, with the exception of spray drying, are designed for retrofit installation where sulfur removal rates from 40 to 70 percent are targeted.[11] The increased flue-gas solids loadings from injected lime solids are removed by existing or add-on electrostatic precipitator or fabric filter particulate-collection devices. Some of these processes are further described in Appendix A.

Finally, regenerative flue-gas scrubbing processes recover the scrubbing reagent while producing a marketable sulfur-containing byproduct. These processes tend to be more complex and somewhat more costly to construct and operate than wet-limestone processes, but they have the advantage of minimizing solid or slurry waste disposal, and of generating revenue from the sale of elemental sulfur, concentrated sulfur dioxide, or sulfuric acid byproducts.

The Wellman-Lord process is the major commercial regenerative sulfur dioxide scrubbing system. Although widely used abroad,

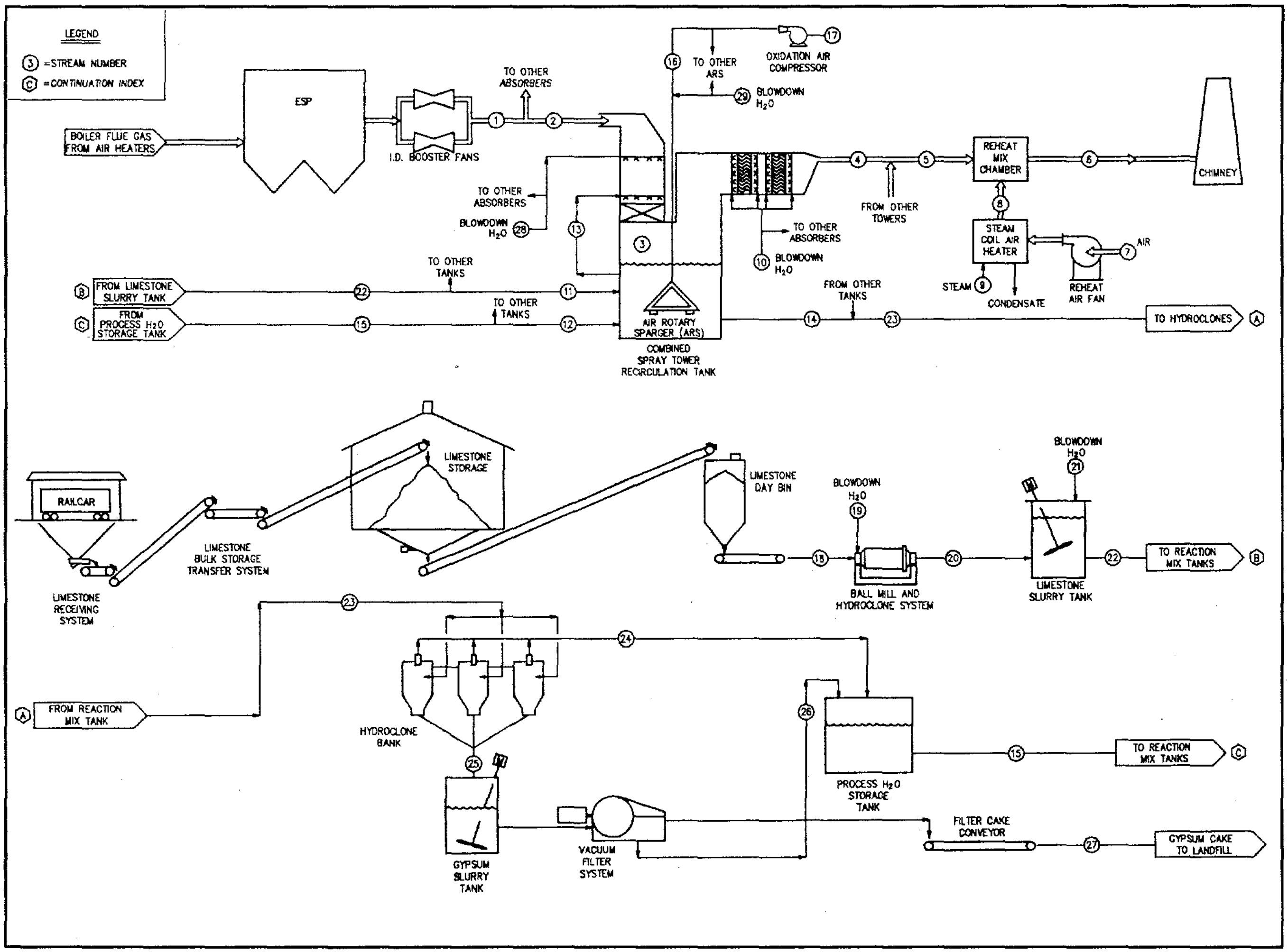

Figure 4. Pure Air FGD Process

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only two domestic plants use the technology due to its cost and complexity. A flow diagram is shown in Figure 5.

Two new regenerative flue-gas desulfurization processes are in the development stages. NYSERDA is co-funding two- to three-MW pilot-scale demonstrations of the Tung and SOXAL processes at Niagara Mohawk Power Corporation's Dunkirk Plant. Evaluations of the two processes estimate that Tung and SOXAL are more energy-efficient and cost less than the Wellman-Lord process. While both these new processes use sodium sulfite as the absorber reagent, they differ in how the spent reagent is regenerated.

The Tung process, as seen in Figure 6, uses an organic solution in a liquid/liquid extraction operation followed by low-temperature steam stripping to regenerate sodium sulfite from the sodium bisulfite absorber effluent. The SOXAL process, as seen in Appendix A, Figure 7, uses standard polymeric electrodialysis membranes and proprietary polymeric bipolar membranes to regenerate the sodium sulfite reagent. In both processes concentrated sulfur dioxide gas is produced that can be further processed into sulfuric acid or elemental sulfur. It is estimated that capital and operating costs are competitive with wet-limestone desulfurization technology. The pilot-plant demonstrations will establish process performance with flue-gas that contains fly ash from a coal-fired boiler, and will verify process economics to the extent possible with these pilot-scale demonstrations.

Operating characteristics for a number of sulfur dioxide emission-control systems are outlined in Table 1. The costs for new plant construction are estimated in Table 2. Retrofit systems generally cost more than grass-roots installations. Cost premiums for retrofit systems are site-specific and difficult to quantify.

Nitrogen Oxide Emission-Control Technology

Nitric oxide and nitrogen dioxide pollutants are combustion products of all fossil fuels. These nitrogen oxide compounds, commonly called NOx, lead to ground-level smog and ozone formation, and contribute to acid precipi-

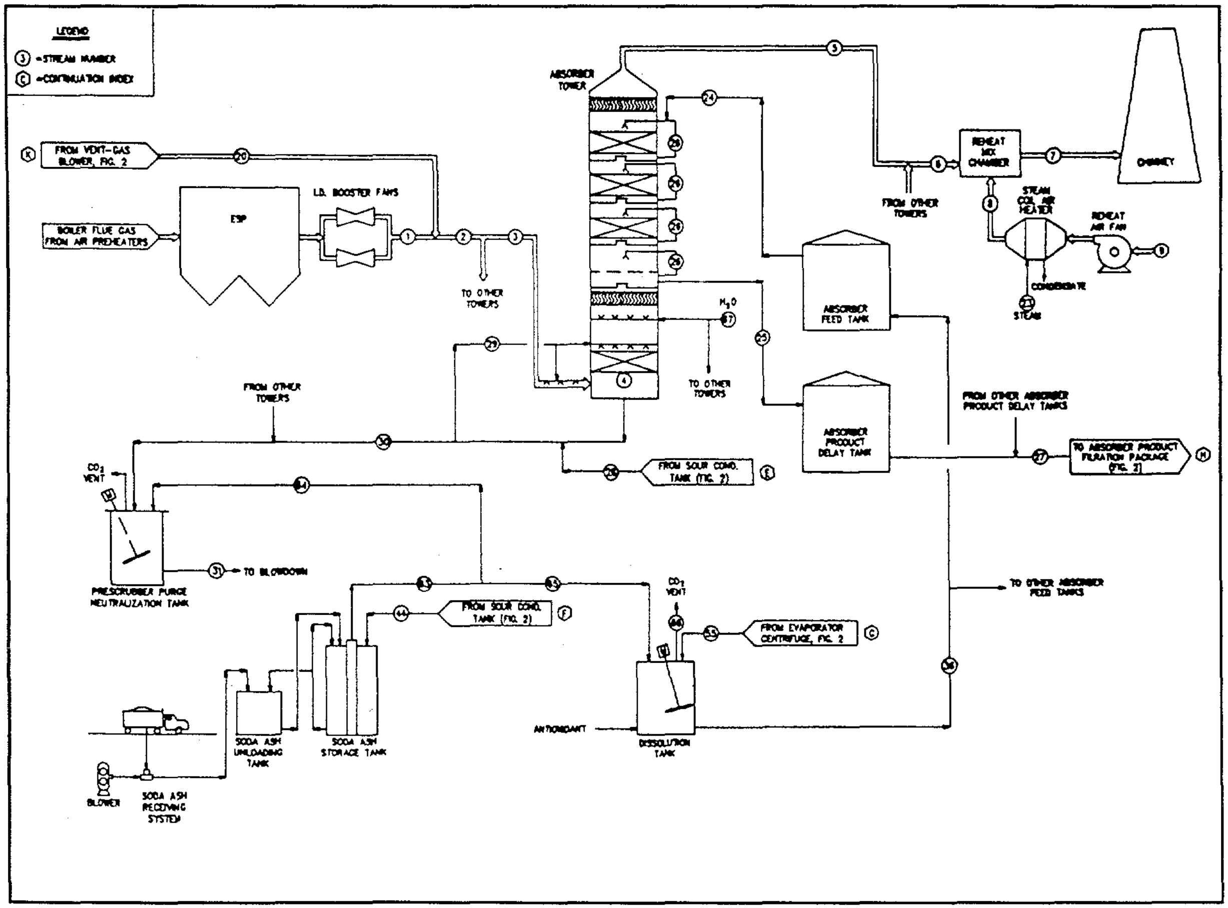

Figure 5. Wellman-Lord FGD Process

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tation. The 1990 CAAA address NOx emissions under Title I, ozone nonattainment, and Title IV, acid rain. Emission limits, to comply with Title I, will undoubtedly be more restrictive compared to Title IV.

NOx forms from the nitrogen present in the fuel (fuel NOx), and from the reaction of nitrogen and oxygen in air at high combustion temperatures (thermal NOx). Coal combustion produces the most and natural gas the least NOx pollutants per unit of energy released. Intense combustion processes with high flame temperatures result in good fuel use and low carbon monoxide emissions, but high NOx emissions. Low-intensity combustion processes tend to be low NOx sources, but may have poor fuel use and higher levels of carbon monoxide emissions.

There are several technologies to control NOx emissions that apply to all fossil fuels. These technologies modify the combustion process to minimize initial NOx formation, or use reagents and/or add-on catalytic converters to reduce NOx in the flue-gas to nitrogen and water. Combustion modifications can reduce NOx emissions from 20 to 50 percent.[12] Reagent-based systems can reduce NOx emissions from 40 to more than 80 percent.[3,13]

Combustion modification technologies, presented in Figure 8, control NOx emissions by reducing combustion intensity and temperature, and by controlling combustion air injection and mixing with fossil fuel. Low-NOx, staged-air admission burners, flue-gas recirculation into the combustion zone of a boiler, the use of overfire air ports to complete combustion above the burners in a boiler, and shutting down a number of burners in a boiler are examples. Combustion modifications tend to be low cost, are usually easily retrofit, and do not significantly reduce plant efficiencies. Plant capacity may, however, be reduced. NOx removal is limited, and the combustion process must be carefully monitored to assure complete fuel combustion, and to warn of operating conditions that may accelerate boiler ash deposition and corrosion.

NOx control systems that use reagents injected into the furnace or boiler flue gas are either catalytic or non-catalytic. Both systems

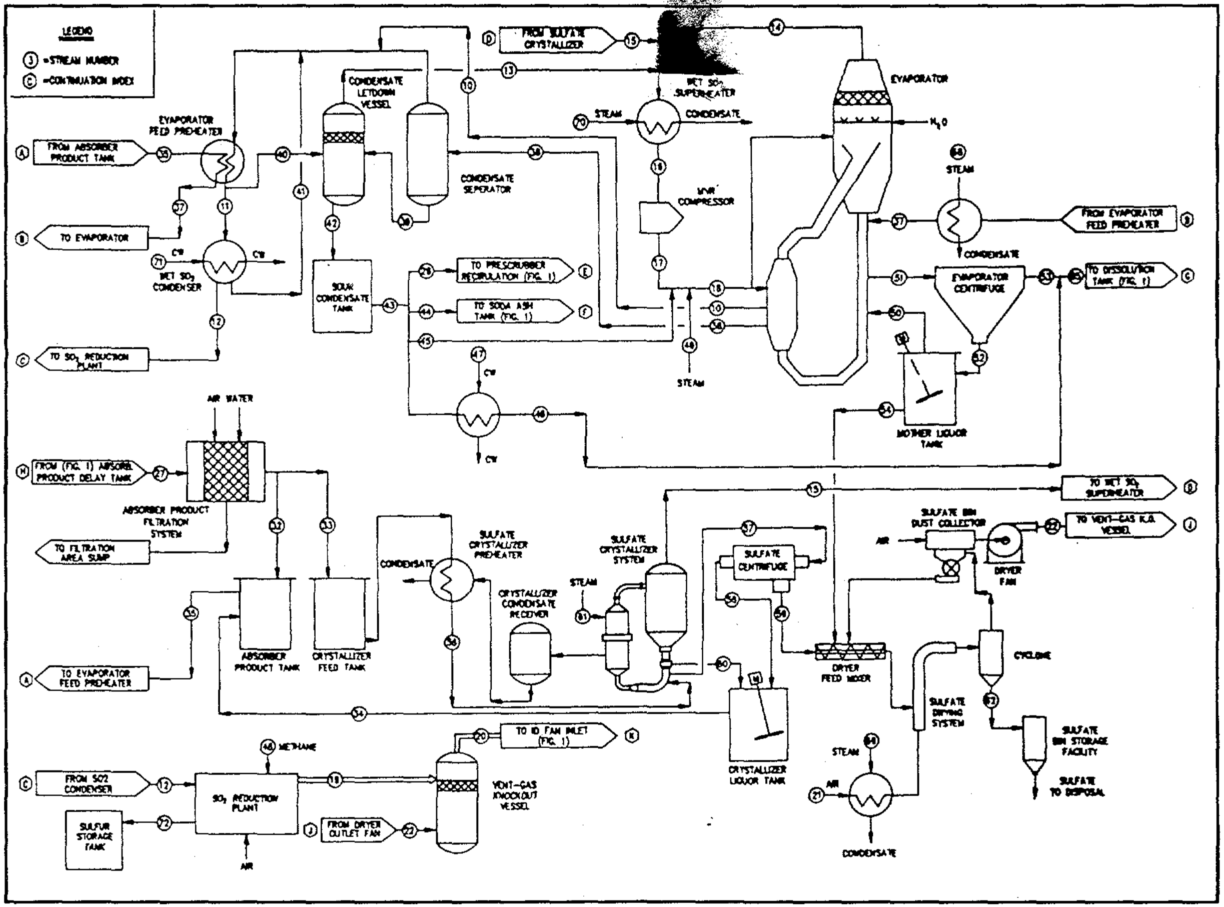

Figure 5. Wellman-Lord FGD Process (cont.)

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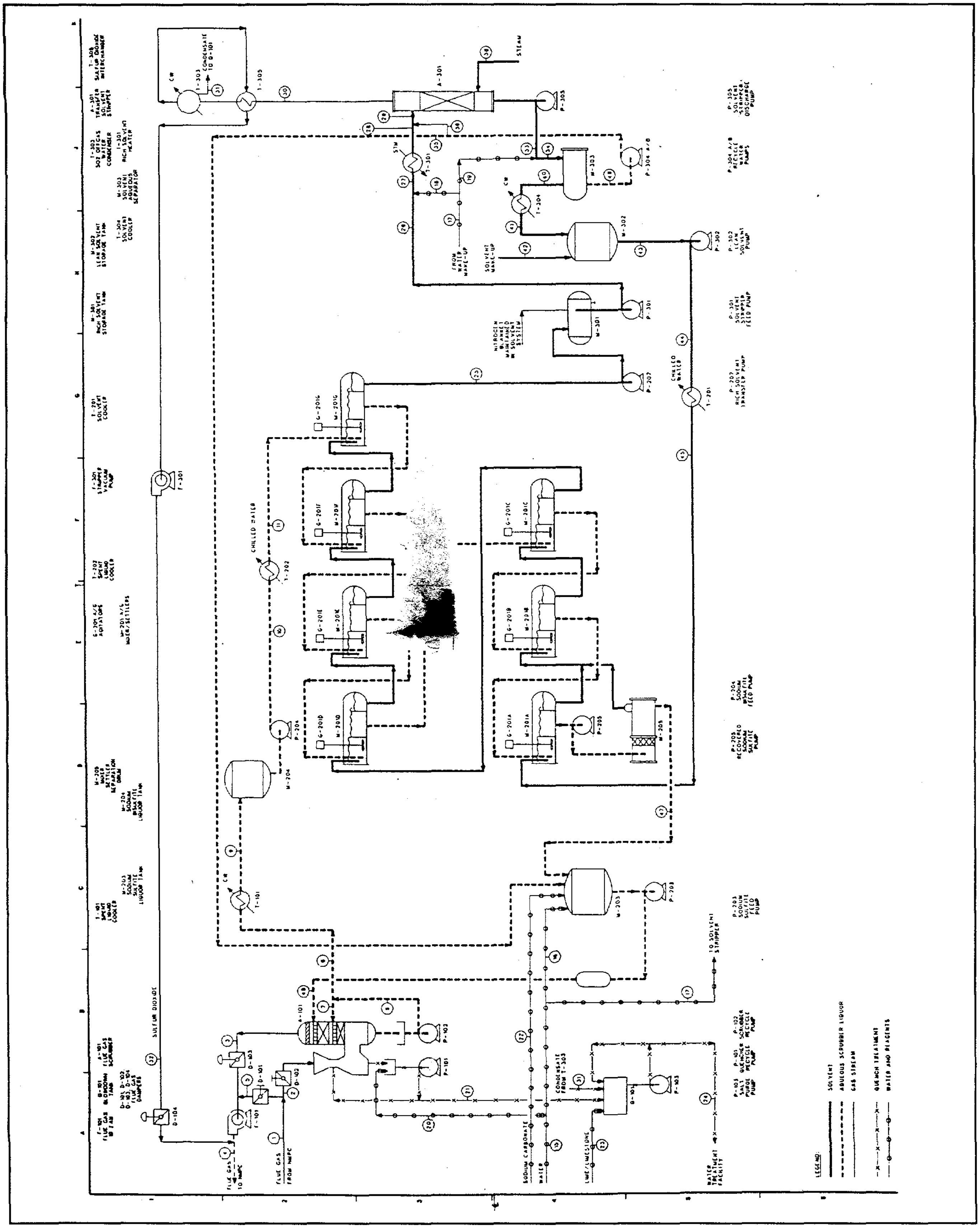

Figure 6. Tung FGD Process

TABLE 1
Operating Characteristics — Sulfur Dioxide Emission-Control Technologies[1,2]

Type	Status	Parasitic Power (% Generation)	Byproducts
Wet Limestone	Commercial	4	Sludge or dewatered gypsum for landfill or wallboard manufacture
CT-121	Commercial overseas, US demonstration	3.5	Dewatered gypsum for landfill or wallboard manufacture
Pure Air	Commercial overseas, US demonstration	3.5	Dewatered gypsum for landfill or wallboard manufacture
Saarberg-Holter	Commercial overseas	3	Dewatered, marketable gypsum and calcium chloride
HYPAS	Pilot demonstration	1	Dry calcium sulfite and sulfate solids for landfill
Lime Spray Drying	Commercial for low-sulfur coal	3	Dry fly ash and calcium sulfite and sulfate solids for landfill
Wellman-Lord	Commercial	5	Sulfur, sulfur dioxide, or sulfuric acid
SOXAL	Pilot demonstration	3	Sulfur, sulfur dioxide, or sulfuric acid
Tung	Pilot demonstration	4	Sulfur, sulfur dioxide, or sulfuric acid

use a reagent to reduce NOx present in the flue gas to nitrogen and water. Non-catalytic processes inject reagent into the boiler or flue gas where temperatures range from 1600° to 2100°F. Catalytic processes operate in the 600° to 750°F range, and inject reagent into a separate reactor vessel.

Non-catalytic processes, called selective non-catalytic reduction (SNCR), inject ammonia or urea into regions of the boiler where flue gas temperatures are optimal for the NOx reduction reaction to occur. A diagram of an SNCR system is shown in Figure 9. Optimum temperature for ammonia is around 1700°F, while 1900°F is best for urea.[13] As boiler load changes, the optimum reaction temperature location changes in the boiler that requires installing multiple reagent injection grids or injection nozzles. Flue-gas composition, specifically carbon monoxide and hydrogen, and flue-gas flow distribution in the boiler affect the NOx reduction reaction.

Experience with SNCR is somewhat mixed. Some boilers have achieved NOx reductions as high as 80 percent; others only 20 percent.[13] This performance range indicates that detailed, specific injection grid design and location in the boiler is critical. The reagent injection control system must be designed to efficiently follow boiler load and inject reagent at the optimum temperature injection nozzles. Care must also be taken to assure that unreacted ammonia, or ammonia produced by the decomposition of urea, does not react with sulfur compounds in the flue gas to form ammonium sulfate or bisulfate that can deposit and plug the air heater. Unreacted ammonia emissions from the boiler stack must be below a permit level. Also, nitrous oxide or laughing gas, an identified greenhouse gas not currently regulated in the United States, is a product of SNCR processes. Extensive testing of SNCR installations at a number of fossil-fuel fired plants is presently under way to evaluate operating problems and refine process economics. NYSERDA is co-funding the demonstration of urea-injection SNCR on a 185 MW oil-fired boiler at Long Island Lighting Company's Port Jefferson Station. Commercial urea-injection SNCR systems are operating on two 85-MW and one 160-MW coal-fired boilers at the Salem Harbor Station of New England Power Company.

In catalytic, or selective catalytic reduction (SCR) processes, ammonia is injected into the flue-gas as it enters a catalytic reactor vessel that can be installed in the flue-gas path at different locations. The most cost-effective location is site-specific, and depends on fuel composition, boiler design and other parameters. The SCR reactor is installed where normal flue-gas temperatures are around 650°F. If the reactor is located upstream of the combustion air heater and/or flue-gas-desulfurization system, it is hot-side SCR. Since flue-gas temperature changes with boiler load, temperature control is achieved by bypassing flue-gas from the boiler around the economizer. Catalysts that function efficiently at flue-gas temperatures encountered at low boiler loads can also be used.

In hot-side installations, the SCR reactor can be installed before or after an electrostatic precipitator (ESP). If the reactor is upstream of the ESP, the catalyst ceramic support must have larger openings to prevent ash-plugging problems. Sootblowers also

TABLE 2
Estimated Costs
Sulfur Dioxide Emission-Control Technologies[1,2]

Type	Capital ($/kW)	Levelized ($/Ton SO_2)
Wet Limestone	150-180	350-450
CT-121	150	350
Pure Air	150	380
Saarberg-Holter	145	380
HYPAS	130	1000
Lime Spray Drying	135	500
Wellman-Lord	217	470
SOXAL	185	500
Tung	200	300

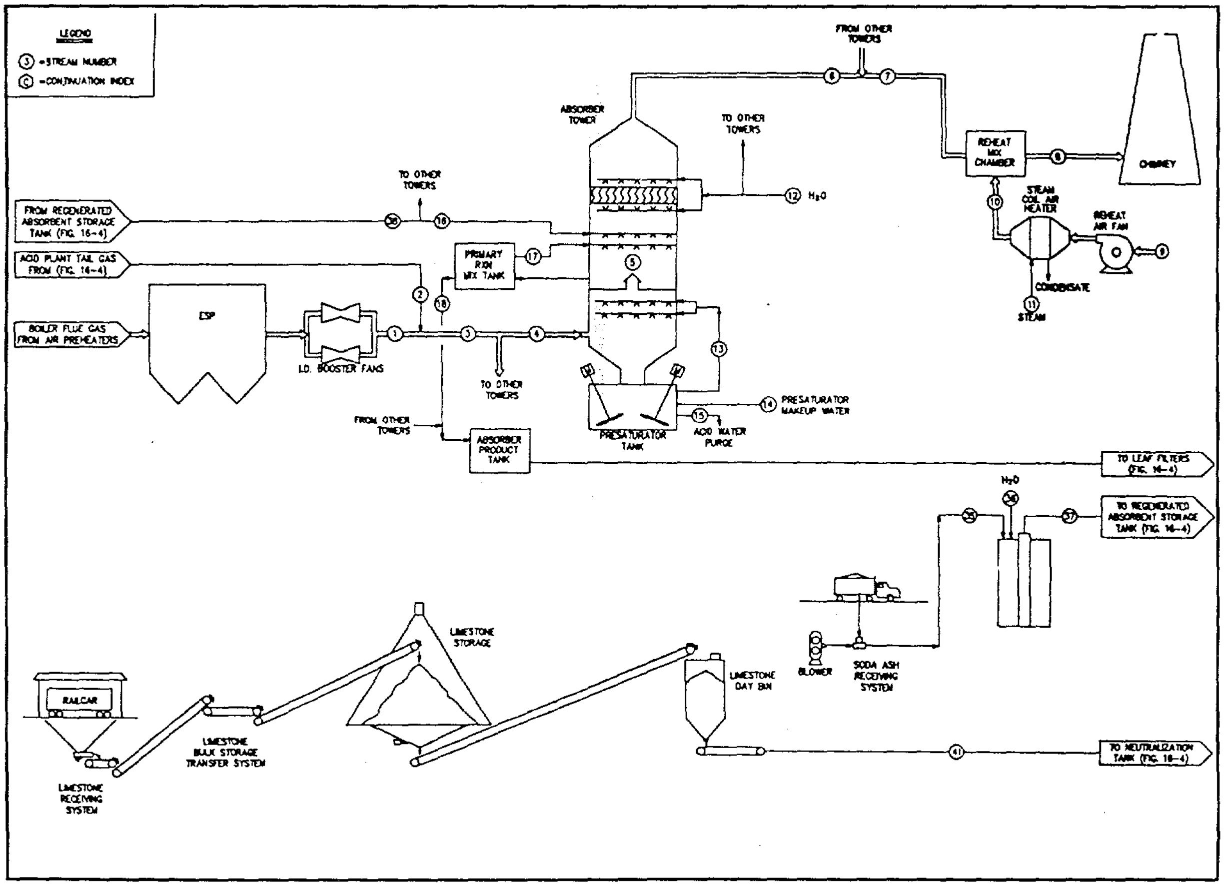

Figure 7. SOXAL FGD Process

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help avoid reactor plugging. This reactor must be operated with care especially during plant startup and shutdown when acid dewpoint temperatures are reached that could deposit alkali sulfate salts in the catalyst support openings and cause catalyst poisoning and plugging. A reactor downstream of the ESP makes smaller catalyst support openings and a more compact reactor design possible.

Cold-side SCR installations avoid reactor deposition problems entirely because the reactor is installed in a low-particulate and low-sulfur concentration environment. The downside to this seemingly best alternative is that energy is required to reheat saturated flue gas from the scrubber to the 650°F SCR reactor temperature, which reduces plant efficiency. The additional energy penalties must be compared to the advantages of improved operations and longer catalyst life when choosing a SCR configuration. NYSERDA is co-funding a 1-MW pilot-scale demonstration of cold-side SCR that uses a novel heat-pipe heat exchanger to heat flue gas to reactor temperature at New York State Electric & Gas Corporation's Kintigh Station.

The demonstration project is evaluating the performance of a number of catalysts supplied by different manufacturers. Results to date indicate that catalyst performance in removing nitrogen oxides from flue gas, and the amount of unreacted ammonia that passes through the catalyst, depends on catalyst chemical formulation and on the design of the catalyst support.

Hot-side and cold-side SCR flow diagrams are shown in Figure 10. Table 3 summarizes operating characteristics of NOx emission-control options. Cost estimates appear in Table 4.

A new technology for exclusively natural gas-fired boilers is being evaluated at Southern California Edison's Mandalay Station. The technology uses an SCR catalyst that is spray-applied to the regenerative Ljungstrom combustion air-heater baskets.[14] Pressure drop and heat-transfer characteristics are not appreciably affected by the catalyst coating on the convoluted metallic heat transfer surfaces. Ammonia is injected upstream of the air heater as in a conventional SCR reactor to avoid the expense of adding a separate catalytic reactor vessel, and the additional induced-draft fan power for

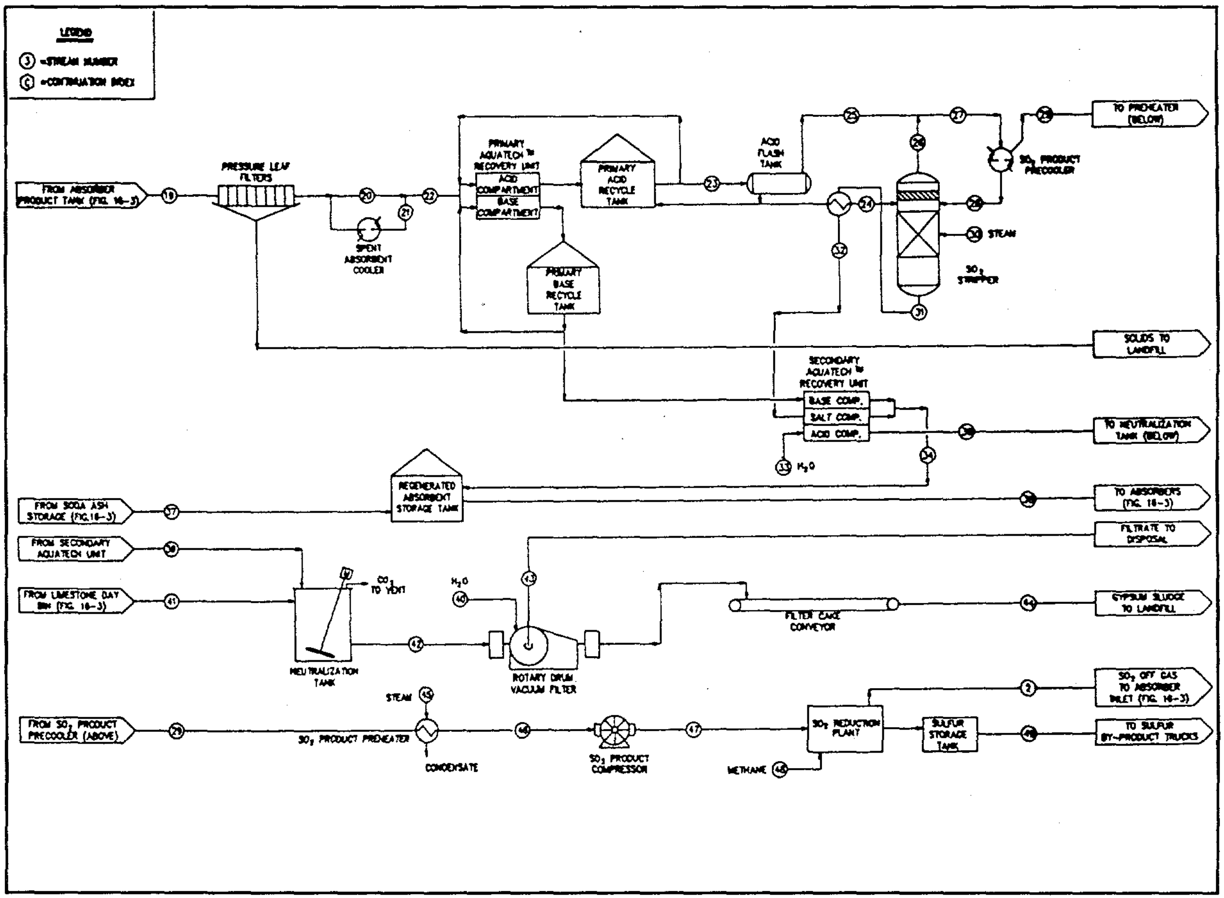

Figure 7. SOXAL FGD Process (cont.)

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overcoming reactor pressure drop. The effect of the shorter gas residence time in the catalytic air heater process compared to a conventional SCR reactor on NOx removal is a major unknown factor. If successful, this technology may be a low-cost way to control NOx emissions from the combustion of low-ash fuels.

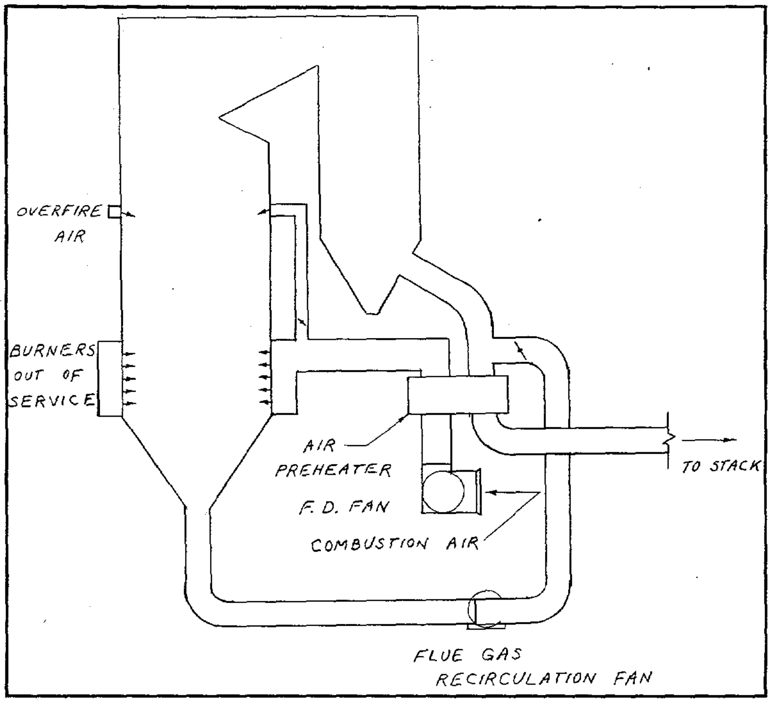

Figure 8. NOx Emission Combustion Control

Particulate Emission-Control Technology

Particulate emissions, a combination of fuel ash and unburned carbon, are transported with the flue gas to the boiler flue-gas stack. Concerns about their effect on health led to regulations that limit total emissions. The realization that respirable-size fine particles less than 10 microns are a serious health hazard has increased legislative interest in limiting their emission.[4] The 1990 CAAA specify that new regulations that address these concerns are to be established.

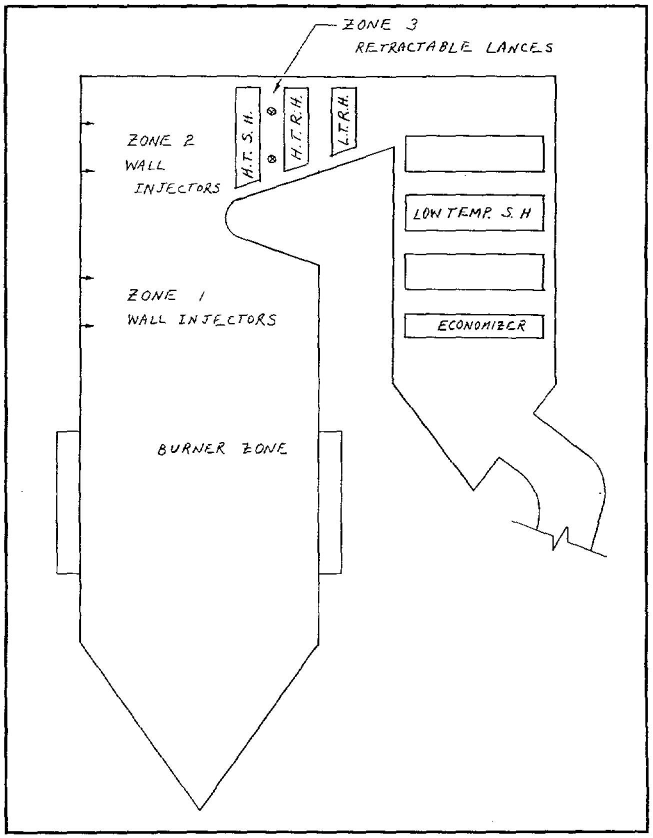

Figure 9. SNCR Process

Traditionally, electrostatic precipitators (ESPs), shown in Figure 11, removed particulate matter from the flue gas of coal-fired and oil-fired plants. ESPs have low pressure drop, low energy consumption, and the power plant can continue to operate if the ESPs have operating problems. However, ESP performance is affected by the electrical resistivity, cohesivity of the collected material, and particle size. Collection efficiency for fine particles less than 10 microns is lower than for larger particles, and this may necessitate extremely large ESP designs or other techniques if increased removal of particles in this size range is required.[4]

Using baghouses for collecting fly ash from coal-fired boilers is increasing because these devices are insensitive to ash composition and characteristics, and because they collect very fine particulate more efficiently than ESPs. The availability of new, durable fabric-filter materials makes baghouses economically competitive with ESPs, particularly for the collec-

TABLE 3
Operating Characteristics — Nitrogen Oxide Emission-Control Technologies[3,13]

Type	Status	Parasitic Power (% Generation)	Environmental Impacts
Combustion Control	Commercial	Negligible	Potential for increased unburned carbon and carbon monoxide emissions
Low-NOx Burners	Commercial	Negligible	Potential for increased unburned carbon and carbon monoxide emissions
SNCR	Commercial	0.5 - 2	Ammonia reagent Unreacted ammonia emissions Formation and emission of nitrous oxide
SCR Hot-side	Commercial overseas, US demonstrations	1 - 1.5	Ammonia reagent Unreacted ammonia emissions Spent catalyst disposal
SCR Cold-side	Commercial overseas, US demonstrations	2.5	Ammonia reagent Unreacted ammonia emissions Spent catalyst disposal

ttion of high resistivity and/or very fine particle-size fly ash. Their chief disadvantage is high flue-gas pressure drop that produces greater energy consumption than ESPs.

Baghouses come in two variations: inside filtering such as reverse-gas cleaning, and outside filtering or pulse-jet cleaning. Both types are shown in Figure 12. In inside-filtering baghouses, the particle-laden flue gas enters the fabric filter through a thimble at the bottom of a top-suspended bag, and deposits the particles on the inside surface. A baghouse has a num-

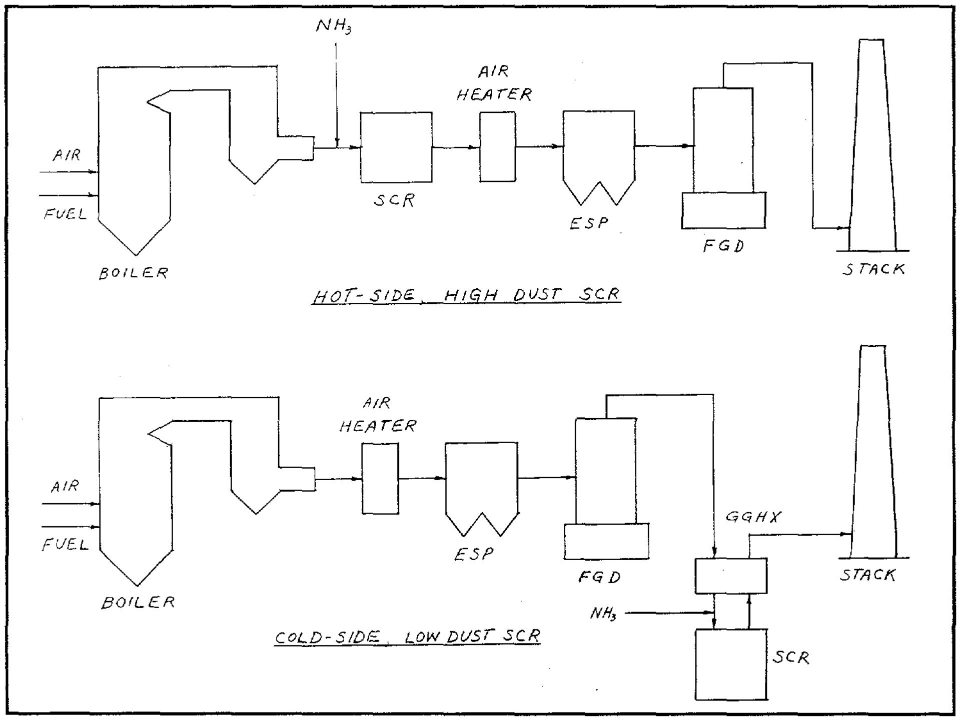

Figure 10. SCR Process

ber of compartments that can be individually isolated from the gas stream. Cleaning occurs when the pressure drop across a compartment reaches a predetermined level. A reverse gas flow across the fabric filter dislodges the accumulated filter cake that is removed from the compartment. Inside-filtering baghouses operate at low gas-to-cloth ratios, usually less than two cubic feet per minute per square foot. While these baghouses tend to be large, inexpensive woven materials can be used for the fabric filters.

Outside-filtering baghouses use the outside surface of a fabric filter supported on a wire mesh cage as the filtering medium. Cleaning is accomplished by pulsing high-pressure gas through the top opening of the fabric filter that dislodges the filter cake from outside the bag for removal from the baghouse. Pulse-jet baghouses operate at higher gas-to-cloth ratios, about five to seven cubic feet per minute per square foot, but use more expensive felted material-type filter bags. Due to their compact size and high-collection efficiency, pulse-jet fabric filters can be installed inside the shell of underperforming ESPs after the internal collecting plates and discharge electrodes are removed.

TABLE 4
Estimated Costs
Nitrogen Oxide Emission-Control Technologies[3,13]

Type	Capital ($/kW)	6Levelized ($/Ton NOx)
Combustion Control		250 - 1800
Low-NOx Burners	5 - 50	250 - 1,800
SNCR	5 - 16	500 - 1,800
SCR Cold-side	100 - 120	2,850 - 4,200
SCR Hot-side	78 - 93	3,300 - 3,800

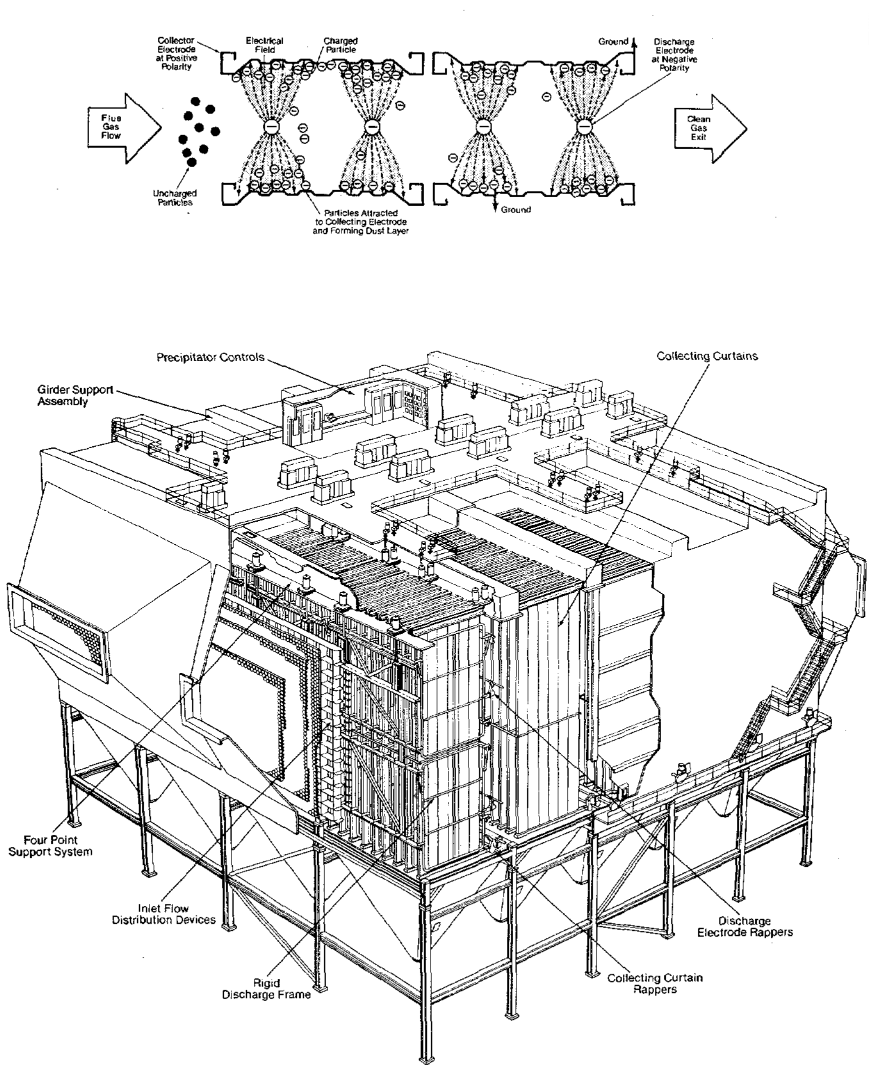

Figure 11. Electrostatic Precipitator (ESP)

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Anticipating CAAA regulations, utilities are considering using compact pulse-jet baghouses downstream of existing ESPs to capture respirable-size particulates that are not removed from the flue gas by the ESP. This may be an economical option to comply with projected regulations.

Collected fly ash from ESPs and baghouses is usually sent to a landfill for disposal. Efforts to find appropriate end uses, depending on composition and physical properties, include cement manufacture, concrete blending, grouting, landfill cover, soil conditioner, and as flowable fill material.

Table 5 summarizes operating characteristics of particulate emission control systems. Table 6 presents

TABLE 5
Operating Characteristics — Particulate Emission-Control Systems[4,5]

Type	Status	Parasitic Power (% Generation)	Advantages	Disadvantages
ESP	Commercial	0.25	• Low pressure drop • Low energy consumption • Malfunction will not cause boiler shut-down	• Low collection efficiency for fine particles • Sensitive to fly ash chemical composition
Reverse-air Baghouse	Commercial	0.35	• Not sensitive to fly-ash composition • High collection efficiency for fine particles	• High pressure drop • Large space requirement • Filter bags can plug and cause boiler shut-down
Pulse-jet Baghouse	Commercial	0.35	• Space requirement same as ESP • High collection efficiency for fine particles	• Expensive filter material • High pressure drop • Filter bags can plug and cause boiler shut-down

estimated costs.

Another promising technology to remove fine particulate is the Integrated Flue Gas Cleaning (IFGC) process. The combination of an atomized water-based absorbing solution spray with condensation of flue-gas moisture results in efficient solid particle/water contacting. Entrained particles as well as condensed volatile species are removed. This process is in the development stage and performance and economics remain to be determined.

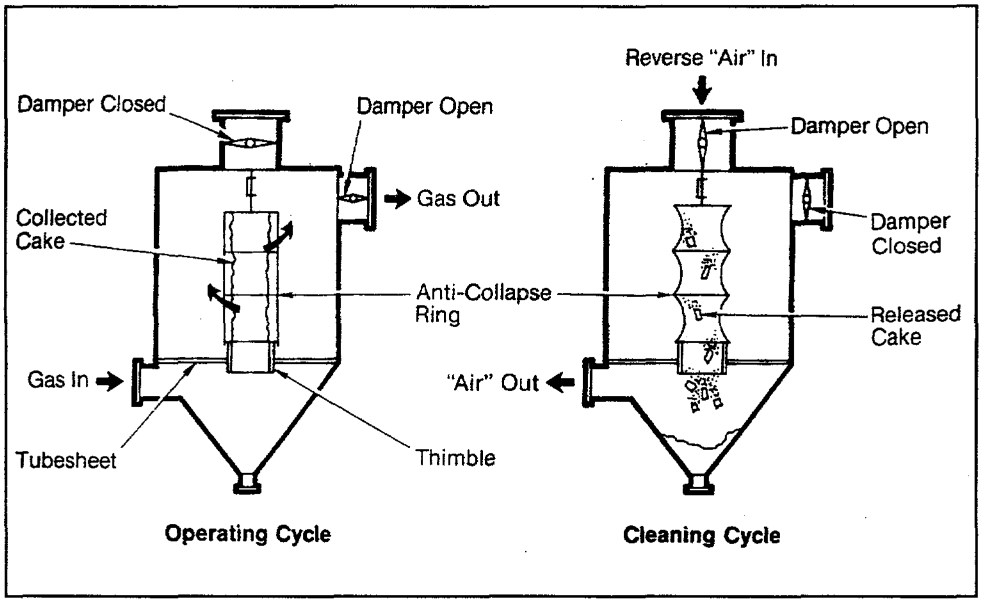

Figure 12. Baghouses

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Pollution-Control System Byproduct Disposal

Nitrogen oxide emission-control systems convert gaseous pollutants to harmless nitrogen gas and water vapor that are emitted with the combustion flue gas. Spent catalyst used in SCR systems for controlling nitrogen oxide emissions is a hazardous material and must be recycled or disposed of in a secure landfill. Sulfur dioxide and particulate control systems produce byproducts that can be further processed into marketable byproducts, or prepared for environmentally safe disposal in a permitted landfill. Currently, coal combustion byproducts are classified as special wastes and do not have to be managed as hazardous or toxic waste.

As previously noted, wet limestone sulfur dioxide control systems convert gaseous sulfur dioxide into a wet sludge containing calcium sulfite, calcium sulfate, unreacted limestone, and fly-ash solids. This sludge is usually aerated to convert sulfite to sulfate because calcium sulfate has superior physical properties that make it more stable, easier to dewater, and give it higher load-bearing compressive strength in a landfill. When market conditions are favorable, the wet sludge can be processed to form a specification-grade, marketable gypsum byproduct for wallboard manufacture.

Dry sulfur-dioxide-removal systems generate a dry waste byproduct for landfilling. The dry waste is usually sprayed with water to control dusting. There may be limited, but useful applications for this byproduct as fill material.

Regenerative sulfur-dioxide-removal systems produce a marketable elemental sulfur, sulfur dioxide, or sulfuric-acid byproduct. Depending on local market conditions, these sulfur byproducts may be net revenue producers for a utility.

Collected particulate fly ash is usually disposed of in a landfill. When there is a wet scrubber and the scrubber sludge is not upgraded, fly ash is blended with the scrubber sludge to improve material properties for landfill disposal. Possible uses for particulate fly ash may be as an additive in cement manufacture, in concrete, as roadbase material, and as a flowable fill. NYSERDA also funded a research project that investigated fabricating blocks from a mixture of scrubber sludge and fly ash to use as an artificial reef in Long Island Sound. According to the research, marine life in the vicinity of the artificial reef did not suffer any deleterious effects.

TABLE 6.
Estimated Costs
Particulate Emission-Control Systems[4,5]

Type	Capital ($/kW)	Levelized ($/kW-yr)
ESP	65	5
Reverse-air Baghouse	75	6
Pulse-jet Baghouse	50	6 - 7

CONCLUSIONS

Current utility pollution-control systems often reduce plant operating efficiency by five percent or more. Given total statewide utility fossil-fuel expenditures in 1991 of about $2 billion, this translates into additional fuel costs approaching $100 million per year to replace lost electric-generating capacity. The emission-control systems also result in more carbon dioxide emissions per unit of electric energy generated. Significant plant efficiency gains with reduced cost and environmental impacts may be achieved, however, using emerging emission control technologies such as those identified in this assessment.

Although sulfur dioxide scrubber chemistry is still not completely understood, sufficient knowledge is available to improve the performance of existing scrubbers, and to design more energy-efficient new ones. Additives such as organic acids, emulsified sulfur, magnesium, and others are used to enhance lime and limestone reactivity, while avoiding scaling, plugging, and sludge dewatering and disposal difficulties. According to published literature, indiscriminate additive use does not guarantee scrubber performance. Additives that work at one utility plant do not necessarily work at others. Because the reasons for this disparity are unclear, pilot-plant testing is frequently required. The Electric Power Research Institute's High-Sulfur Test Center in Somerset, New York, operated with NYSERDA support, investigates specific scrubber problems.

Emission-control systems either minimize the formation of nitrogen oxide and nitrogen dioxide, or reduce gaseous nitrogen oxides to molecular nitrogen gas, the main constituent of air, and water vapor. Except for the possibility of unreacted ammonia emissions, and spent catalyst disposal, nitrogen oxide control systems do not produce byproducts for disposal or reuse. In the future, research will undoubtedly focus on reducing cost and increasing the performance of nitrogen oxide reduction catalysts.

Particulate control technology will be affected by regulations requiring increased removal of respirable-size particulates. These collection systems will consume more energy than current systems. Many techniques, such as improved flue-gas flow distribution, pulse energization, special discharge electrode designs, modern electronic voltage control systems, reverse polarity operation, and precharging, will be evaluated to improve ESP performance. Using chemical additives such as sulfur trioxide and ammonia to condition the flue gas also appears promising to bring existing ESPs into particulate emission compliance.

Baghouses may become more competitive with ESPs in meeting increasingly stringent emission regulations. Compact pulse-jet baghouses appear to control respirable-size particulate emissions that are not efficiently collected in existing ESPs.

While some of the advanced emission control technologies discussed in this report are commercially available today, many more are at the development/demonstration stage. It is critical, therefore, that support for such technology research be maintained if their benefits are to be realized.

Appendix A
Sulfur Dioxide Emission-Control Systems

Sulfur dioxide control systems can be broadly classified into three types: wet limestone with disposal or possible use of a sludge or dewatered byproduct; dry lime which produces a dry waste byproduct for disposal; and the regenerative processes that use reagents to produce sulfur dioxide, sulfuric acid, or elemental sulfur byproducts.

Wet lime or limestone scrubbing for sulfur dioxide emission control produces large quantities of sludge for disposal. A plant burning a four percent sulfur coal using simple settling for sludge dewatering can produce as much as 1200 pounds of waste material per ton of coal burned which amounts to 6000 tons per day of wet sludge for a 1000-MW plant. Early scrubbing systems pumped untreated sludge to on-site or nearby lined sludge-settling ponds for disposal. Although low in energy consumption, this practice is no longer acceptable because appropriate sites are not readily available; liners are expensive to install; there are environmental concerns about liner leakage; and, the solids left in the sludge ponds after dewatering are physically unstable due to the presence of calcium sulfite.

Current scrubbing systems include additional energy-consuming processing to upgrade waste material for improved handling and disposal in compliance with regulations. Air is pumped through the absorber tower sump to oxidize calcium sulfite to calcium sulfate which is easier to dewater mechanically, and which is physically stable. Mechanical dewatering equipment is used to reduce the water content of the solid waste material. Fly ash and lime are frequently blended with the dewatered sludge to produce a material that undergoes pozzolanic, cement-like hardening reactions. This material, when cured, minimizes leachate run-off concerns and has sufficient strength to support the construction of buildings.

Efforts to improve the energy efficiency of lime and limestone-scrubbing systems focus on increasing reagent reactivity without inducing operating problems. Higher reactivity reduces power consumption in pumping slurry through the absorber tower, and lowers energy requirements to process and dispose of less waste material. Improved gas/slurry-contacting absorber designs may also improve reagent use, but potential energy savings in slurry preparation and pumping may be offset by increased induced-draft fan power requirements due to higher pressure losses through the absorber.

Scrubber chemistry is still not completely understood, but an improved understanding of the process is possible by analyzing the operating performance of first-generation scrubbing systems. Additional information is available from pilot facilities such as EPRI's High-Sulfur Test Facility. Research has led to the successful use of a number of chemical additives that improve existing scrubber performance, and reduce capital and operating costs of new scrubbing systems. Additives such as organic acids, emulsified sulfur, and magnesium can enhance sulfur dioxide removal and limestone use without leading to scaling, plugging, and sludge dewatering problems of the early scrubber designs. Experience gained from operating first-generation scrubbers is used in selecting construction materials that minimize corrosion for new scrubber designs.

Dry-scrubbing technologies produce a solid waste product that does not require dewatering, and is easier to dispose of. In fact, with dry systems, water is frequently sprayed into the solid waste to control dusting. With dry scrubbing, a sorbent such as lime or limestone is injected dry, or as a water slurry, into the boiler, or into the downstream flue-gas ducting. Sodium-based salts can also be used; however, this presents solid waste disposal problems because sodium sulfite and sodium sulfate waste products are water soluble. The actual sulfur dioxide absorption can occur either as a gas/solid, or as a gas/liquid reaction. The additional flue-gas particulate loading from the injected adsorbent is removed in collection equipment, usually an electrostatic precipitator, but sometimes a baghouse.

Furnace injection systems inject limestone into the furnace where it calcines to calcium oxide that reacts with sulfur dioxide in a gas/-solid reaction. The time and temperature exposure of the injected limestone is important in producing a reactive reagent. In general, these processes do not use reagent effectively, and result in sulfur dioxide reductions of from 20 to 30 percent. Increased sulfur is captured by humidifying flue-gas leaving the boiler air heater with water injection that activates unreacted calcium sorbent particles and facilitates additional sulfur dioxide removal. Humidification also improves the performance of a downstream ESP. Sulfur removals above 50 percent are achievable using this approach.

Duct-injection systems use hydrated lime as reagent, and inject it into the flue-gas ducting upstream of the particulate-control device. An example is the HYPAS Process, developed with Energy Authority support. While humidification usually improves sulfur removal and ESP performance, it must be controlled to avoid saturation when water impingement on duct surfaces may lead to deposit formation. If a baghouse controls particulate emissions, additional sulfur removal occurs on the calcium-rich filter cake of the fabric filters. Sulfur dioxide removals from 50 to 60 percent were demonstrated at pilot-scale facilities.

Spray-drying systems atomize a hydrated-lime slurry in an absorber vessel where flue gas contacts the slurry spray. Sulfur dioxide reacts with the lime reagent as flue-gas sensible heat evaporates the slurry water. A dry solid waste collects and is periodically removed from the bottom of the absorber vessel. Entrained flue-gas particles pass through a baghouse where additional sulfur removal occurs on the fabric filter cake. Spray-drying systems were initially developed for controlling sulfur emissions from low-sulfur western domestic coals, but are now available for use with high-sulfur eastern coals.

Regenerative flue-gas scrubbing systems recover the reagent and produce a marketable sulfur byproduct. Regenerative systems are currently more complex and cost more to construct and operate than wet lime/limestone throwaway, or dry-lime systems. These systems minimize solid waste disposal requirements, and provide revenue from the sale of sulfur byproducts. The market, however, for sulfur byproducts is site-specific, and may become saturated if many coal-fired power plants use this technology.

These systems typically use a sodium sulfite water solution as the reagent that prevents absorber scaling and plugging problems. The sodium sulfite reacts with sulfur dioxide in the flue gas to form sodium bisulfite. Additional processing converts sodium bisulfite back to sodium sulfite, and a concentrated sulfur dioxide gas stream. Depending on market conditions, liquid sulfur dioxide, elemental sulfur, or sulfuric acid can be produced for sale.

A new, developing technology for removing sulfur dioxide from the flue-gas of coal- and oil-fired plants is the CHX Integrated Flue Gas Treatment (IFGT) process. This technology is particularly attractive when plants operate in a cogeneration cycle because it combines flue-gas cleanup with heat recovery. In addition, IFGT may capture volatile heavy metals and fine fly-ash particles.

Appendix B
Nitrogen Oxide Emission Standards

Nitrogen oxides, via complex atmospheric reactions, are precursors for the formation of ground-level ozone, and parts of New York State exceed ozone air-quality standards. In addition, NOx emissions contribute to acid rain formation.

All fossil-fuel fired plants in New York State will be required to limit nitrogen oxide (NOx) emissions; however, final allowable emission limits remain to be determined. Preliminary NOx reduction targets under Phase I of the CAAA are 0.38 lbs/MBtu for coal, 0.25 lbs/MBtu for oil, and 0.20 lbs/MBtu for natural gas. Under Phase II, preliminary NOx emission targets are 0.1 lbs/MBtu for oil and gas, and 0.2 lbs/MBtu for coal.

Appendix C
Particulate Emission-Control Systems

ESP particulate emission-control technology has a long operating history, and is widely used to capture flue-gas fly-ash from coal- and oil-fueled boilers. Collection efficiency is optimum when fly-ash electrical resistivity is from 10^{-9} to 10^{-10} ohm-cm. Fly- ash resistivity is affected by temperature and ash composition, particularly sulfur content. Fuel switching to lower sulfur fuels to be in compliance with sulfur dioxide emission limits may result in reduced ESP performance, and particulate emission non-compliance. ESP performance enhancement or upgrading is then required.

These techniques improve performance in varying degrees with specific fly-ash, but are often ineffective, or only marginally effective, when fly-ash composition changes. Short of increasing the physical size of an ESP (some existing ESPs are larger than the boiler house) by adding collecting fields, only flue-gas conditioning is a commercially accepted practice to improve performance of existing ESPs, and for designing new, cost-effective, lower-energy-consuming ESPs. Controlled sulfur trioxide (SO_3) and ammonia (NH_3) additions to the flue gas are generally effective in enhancing ESP performance, and in improving the collection of fine particulates. SO_3 is effective in reducing ash resistivity, and NH_3 improves the cohesivity of ash deposited on the collecting plates. Improved cohesivity minimizes entrainment when the plates are rapped for ash removal from the ESP. Recent testing demonstrated that dual flue-gas conditioning improves the collection efficiency of an ESP in removing fine, respirable-size particles.

Baghouses, or fabric filters, have not been used extensively due to higher flue-gas pressure drops and higher induced-draft-fan energy consumption, and due to uncertainty about the operating life of individual bags, or fabric filters. There was also some concern about the repeated cleanability of the individual bags, and the possibility of bag blinding, whereby fly-ash particles would penetrate the bag fabric so they could not be removed, which would impede flue-gas flow and lead to a boiler shutdown. Contrary to the performance of ESPs, baghouses are not sensitive to the chemical properties of fly-ash, and are superior in collecting particulates smaller than 10 micons. Experience gained from operating several utility-scale baghouses has more clearly defined advantages and limitations. Coupled with progress made in developing improved bag materials that have extended bag service life, baghouses are, in many cases, now competitive with ESPs.

Appendix D
New York State Fossil-Fueled Steam-Generating Plants[16] by Unit, Capacity/MW, Primary Fuel

Central Hudson Gas & Electric Corporation

Danskammer 1	63	Oil
Danskammer 2	59	Oil
Danskammer 3	134	Coal
Danskammer 4	235	Coal
Roseton 1	210	Oil
Roseton 2	210	Oil

Consolidated Edison Company of New York, Inc.

Arthur Kill 2	335	Oil
Arthur Kill 3	491	Oil
Astoria 1	171	Oil
Astoria 2	171	Oil
Astoria 3	353	Oil
Astoria 4	361	Oil
Astoria 5	361	Oil
East River 5	130	Oil
East River 6	130	Oil
East River 7	170	Oil
Hudson Ave. 10	44	Oil
Ravenswood 1	385	Oil
Ravenswood 2	385	Oil
Ravenswood 3	972	Oil
Waterside 5,7,8,9,14,15	306	Oil
59th Street 14,15	35	Oil
74th Street 9,10,11	147	Oil

Long Island Lighting Company

Barrett 1	192	Oil
Barrett 2	195	Oil
Far Rockaway 4	115	Oil
Glenwood 4	111	NG
Glenwood 5	117	NG
Northport 1	382	Oil
Northport 2	383	Oil
Northport 3	381	Oil
Northport 4	381	Oil
Port Jefferson 1	47	Oil
Port Jefferson 2	46	Oil
Port Jefferson 3	194	Oil
Port Jefferson 4	195	Oil

New York Power Authority

Poletti 1	825	Oil

New York State Electric & Gas Corporation

Goudey 7	45	Coal
Goudey 8	84	Coal
Greenidge 3	55	Coal
Greenidge 4	108	Coal
Hickling 1	36	Coal
Hickling 2	51	Coal
Homer City 1	311	Coal
Homer City 2	312	Coal
Homer City 3	327	Coal
Jennison 1	35	Coal
Jennison 2	39	Coal
Kintigh	691	Coal
Milliken 1	157	Coal
Milliken 2	161	Coal

Niagara Mohawk Power Corporation

Albany 1	100	NG
Albany 2	100	NG
Albany 3	100	NG
Albany 4	100	NG
Dunkirk 1	90	Coal
Dunkirk 2	90	Coal
Dunkirk 3	195	Coal
Dunkirk 4	204	Coal
Huntley 63	85	Coal
Huntley 64	85	Coal
Huntley 65	85	Coal
Huntley 66	85	Coal
Huntley 67	185	Coal
Huntley 68	190	Coal
Oswego 1	0	Oil
Oswego 2	0	Oil
Oswego 3	75	NG
Oswego 4	90	Oil
Oswego 5	850	Oil
Oswego 6	850	Oil

Orange and Rockland Utilities, Inc.

Bowline 1	200	Oil
Bowline 2	203	Oil
Lovett 1	0	Oil
Lovett 2	16	Oil
Lovett 3	62	Oil
Lovett 4	181	Coal
Lovett 5	207	Coal

Rochester Gas and Electric Corporation

Beebee 12	80	Coal
Russell 1	47	Coal
Russell 2	65	Coal
Russell 3	65	Coal
Russell 4	80	Coal

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