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STATUS OF FLUE-GAS TREATMENT TECHNOLOGIES FOR COMBINED SO_2/NO_x REDUCTION

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STATUS OF FLUE-GAS TREATMENT TECHNOLOGIES FOR COMBINED SO_2/NO_x REDUCTION

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ABSTRACT

Enactment of the Clean Air Act Amendments and passage of state legislation leading to more stringent nitrogen oxides (NO_x) regulations have fueled research and development efforts on the technologies for the combined control of sulfur dioxide (SO_2) and NO_x. The integrated removal of both SO_2 and NO_x in a single system can offer significant advantages over the use of several separate processes, including such factors as reduced system complexity, better operability, and lower costs. This paper reviews the status of a number of integrated flue-gas-cleanup systems that have reached a significant stage of development, focusing on post-combustion processes that have been tested or are ready for testing at the pilot scale or larger. A brief process description, a summary of the development status and performance achieved to date, pending commercialization issues, and process economics (when available) are given for each technology.

INTRODUCTION

The development of advanced flue-gas-cleanup (FGC) technologies for the control of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions continues to be a very active area of research and development, both in this country and abroad. This activity is driven both by legislation (such as the recent revisions to the Clean Air Act) and by the desire to develop technologies that surpass current options in terms of performance, costs, operability, and waste/by-product properties. New issues, such as concern over global climate changes and the health effects of toxic air emissions ("air toxics"), are also helping to shape and prioritize the development programs.

Commercially applied control technologies have typically involved combustion-modification techniques for NO_x and some form of wet scrubbing for SO_2. Recently, both selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) for NO_x control have achieved commercial status for some applications, spray-dryer technology has led to the development of a wet/dry scrubber system for SO_2 that produces an easily handled dry waste, and various duct-injection processes have demonstrated moderate levels of SO_2 control. Ongoing development programs address a wide variety of alternative technologies that include a number of integrated processes for the removal of both SO_2 and NO_x in a single system. Such integration generally reduces system complexity and costs, enhances operability/reliability, and takes advantage of beneficial synergisms between pollutants in the removal process.

This paper provides a status report on a number of integrated FGC systems that have reached a significant stage of development, focusing on post-combustion processes that have been tested or are ready for testing at the pilot scale or larger. Although a wide variety of technologies is discussed, it should be noted that there are a number of other integrated approaches, such as slagging combustors, fluidized-bed combustion, gasification/combined-cycle systems, and various processes combining low-NO_x burners with SO_2-sorbent injection in the furnace. These other approaches also offer features that should not be overlooked when evaluating alternatives for a specific application.

TECHNOLOGY SUMMARIES

In order to achieve mandated air quality objectives as rapidly as possible, it is clear that emissions control equipment will have to be installed at many existing facilities. Almost any technology can be installed as a retrofit, given sufficient resources, but the realities of plant layout, operating characteristics, and/or remaining service life can make such an installation exceedingly difficult and inordinately expensive. The first two technologies described in this section are especially relevant to these issues, having been developed specifically for retrofit of NO_x control to existing flue-gas desulfurization (FGD) systems, a particularly important consideration for the many facilities with existing scrubbers. The third technology, in-duct sorbent injection, is being developed as a low-cost retrofit of both SO_2 and NO_x control that avoids the installation of major equipment items. The remaining technologies are complete systems that are not only designed to remove both species (and perhaps particulate matter (PM) as well), but that also involve more extensive equipment requirements. Note that unless explicitly stated otherwise, the existence of an electrostatic precipitator (ESP) or baghouse for PM control is assumed in all cases. While the performance of the PM-control device is not emphasized here, its importance can be expected to increase in the future in connection with the capture of fine-particulate matter carrying air toxics.

Wet Scrubbing with Metal Chelates

The dominant FGD technology today is wet scrubbing based on limestone, lime, or sodium carbonate. All of these processes are capable of over 90% SO_2 removal, but they are largely ineffective for NO_x removal due to the low solubility of the principal species, nitric oxide (NO). In view of the large number of wet scrubbers already in place or planned for the near future, a process that promotes NO_x removal simply through the addition of chemical additives, as indicated in Figure 1, could have a significant impact on control strategies.

It has been found that some metal-chelate additives, such as ferrous ethylenediaminetetraacetate ($Fe(II)\bullet EDTA^{2-}$), promote NO_x removal because they quickly remove any absorbed NO from solution and thereby maximize the absorption driving force. The coordinated NO can react with a sulfite ion, freeing the ferrous chelate for further reactions with NO. This synergism makes external regeneration of the Fe(II)•EDTA to release the NO unnecessary. Laboratory tests at Argonne National Laboratory (ANL) have given NO_x removals of up to about 60% for SO_2 removals of 90% (1). Higher levels of removal can be achieved with more vigorous gas/liquid contacting. Wastes contain the usual FGD products (e.g., $CaSO_3/CaSO_4$), together with nitrogen-sulfur compounds and perhaps other species.

A significant process problem is oxidation of the iron in the additive to the inactive, ferric state. Research efforts have been directed at the investigation of "secondary" additives with antioxidant/reducing properties (1), reduction of ferric to ferrous ions using bisulfite ions in the scrubber liquor (2), and reduction using an electrochemical cell (3).

Pilot-scale tests of the technology were conducted during 1991 by the Dravo Lime Company with support from the U.S. Department of Energy (DOE). The tests utilized a 4.5-MW pilot plant constructed by Dravo at the Miami Fort Station of the Cincinnati Gas and Electric Company. Conditions investigated during the experiments included the liquid-to-gas ratio, gas velocity, scrubber packing materials, flue-gas SO_2 and NO_x concentrations, and ferrous ion concentration in the scrubber liquor. An antioxidant was used to maintain the desired ferrous ion concentration. Nitrogen oxides removals of up to 60% were obtained using packing in the scrubber tower. The corresponding SO_2 removals were essentially 100% (4). A thorough physical and chemical characterization of the waste produced is currently being conducted by Dravo and ANL.

Modified Spray-Dryer Scrubbing

Spray-dryer FGD technology is based on the spray drying of an alkali sorbent, typically lime slurry, followed by collection of the resulting particulate matter. The slurry is atomized and mixed with hot flue gas, which evaporates virtually all of the water while SO_2 is simultaneously absorbed and reacted with the alkali. The resulting dry powder and fly ash are collected in either a baghouse or an ESP and sent to a landfill for disposal. Process simplicity, low energy and water consumption, and the dry state of the waste are significant advantages. Sulfur dioxide removals of up to 90% have been demonstrated in both low- and high-sulfur applications (5).

Very little NO_x is removed under normal operating conditions, but research at the Pittsburgh Energy Technology Center (PETC) showed that elevated spray-dryer exit temperatures and the addition of sodium hydroxide (NaOH) to the lime can promote significant NO_x removal (6, 7). Full-scale (20-MW) demonstration of this technology was carried out in two series of tests at ANL using flue gas from the firing of high-sulfur (3.5%) coal and the process configuration shown in Figure 2. Raising the spray-dryer exit temperature from the normal value of about 65°C to above 82°C initiates NO_x removal, which is accompanied by some net nitrogen dioxide (NO_2) increase in the stack gas, ranging from 6-18 ppm. The addition of NaOH at 2.5-10% by weight of lime improves NO_x removals and reduces the lime requirement for SO_2 control. Most of the NO_x removal occurs in the baghouse, and extended intervals between bag cleanings produce the best performance, with average values of about 35% being attained at ANL. With some operating modifications, NO_x removals up to 50% should be attainable. Removals also depend strongly on the SO_2/NO_x ratio, being higher for high SO_2 concentrations in the flue gas (8). It should be noted, however, that the temperatures needed to promote NO_x removal also tend to suppress SO_2 capture, making it difficult to simultaneously optimize both NO_x and SO_2 control.

Detailed costs for the process are not available, but one preliminary estimate projected operating costs about 20% higher than those for normal SO_2 scrubbing (8). Process uncertainties are related to waste characteristics (solubility of sodium compounds) and long-term steady-state performance. Note that this technology represents a fully integrated $SO_2/NO_x/PM$ process.

In-Duct Sorbent Injection

Several process concepts (summarized in Figure 3) use in-duct injection of sorbents to achieve combined SO_2/NO_x control or to supplement other removal measures. In one of these processes, being developed by Research-Cottrell Environmental Services and Riley Stoker, alcohol-hydrated lime is injected into the convective section of the boiler (at about 540°C) for primary SO_2 control. Sodium bicarbonate is injected in the flue-gas duct at about 150°C for NO_x removal and additional SO_2 control. Urea injected with the sodium bicarbonate helps control unwanted NO_2 production. Small-scale tests have given 90% SO_2 removal, and overall NO_x removals of up to 75% have been projected for the process when combined with low-NO_x burners (9).

Process development is continuing on a 7,000 scfm proof-of-concept unit. Uncertainties involve trade-offs between temperature and urea for NO_2 control, demonstration of high SO_2 removals at reasonable sorbent consumption, and disposal properties of the waste generated. A preliminary economic analysis reported in 1990 gave capital costs of $50/kW and levelized operating costs of about 10 mills/kWh (10).

Another process, which was selected for testing under the third round of the DOE Clean Coal Technology Program, is being developed by a team led by the Public Service Co. of Colorado. Process plans call for a combination of several subsystems utilizing different emission control mechanisms to achieve the desired reductions. For NO_x control, Unit 4 (100-MW) of the Arapahoe Power Plant is to be retrofitted with Babcock & Wilcox low-NO_x burners and overfire air, supplemented by urea injection into the furnace. In-duct injection of either calcium or sodium-based sorbents, supplemented by flue-gas humidification, will be used for SO_2 control. A baghouse will control PM and provide a site for additional SO_2 removal. Up to 70% removal of both SO_2 and NO_x is expected (11). The urea injection system has been installed and is in the process of shakedown, while the other various subsystems are in the design phase. Process testing is expected to begin in the fall of 1992.

Dry sodium bicarbonate injection has also been tested at five coal-fired utility boilers by NaTec Resources, Inc., and has been commercially installed at several industrial sites. Removal values have been as high as 75% for SO_2 and have ranged from 0-40% for NO_x on systems equipped with ESPs. Sulfur dioxide removals as high as 90%, with 25% NO_x removal, were obtained in small-scale tests with injection upstream of a baghouse. Solubility of the wastes requires a lined pond with a leachate collection system for disposal. To enhance the attractiveness of the process, recent development efforts have been focused on recovery of sodium sulfate (Na_2SO_4), a commercially valuable by-product. However, full-scale tests have yet to be conducted for a complete scrubbing/by-product system. Projected costs reported by the developer in 1990 for such a system were $81/kW capital cost (including a new baghouse) and 5.05 mills/kWh levelized cost (12).

NOXSO Process

The NOXSO process is a dry, regenerable FGC system designed to simultaneously remove over 95% of the SO_2 and 70% of the NO_x from flue gas. The gas is cleaned as it passes through a fluidized bed of sodium-impregnated alumina sorbent at about 120°C. Removal of PM can be accomplished either before or after the process. The reaction mechanisms are complex, giving a variety of sulfur- and nitrogen-containing compounds in the spent sorbent (13).

Regeneration of the sorbent is performed separately for NO_x and SO_2. Adsorbed NO_x is released as the sorbent is heated to about 620°C with hot air in a second fluidized bed, as shown in Figure 4. The off-gas can be recycled to the combustor with the combustion air. As a result of chemical equilibria in the combustor, NO_x formation is suppressed, resulting in a new, slightly higher, steady-state NO_x concentration in the flue gas. Thus, the only NO_x removal by-product is nitrogen (N_2). After heating, the sorbent is treated with a reducing gas, such as methane, and steam to produce a concentrated stream of SO_2 and hydrogen sulfide (H_2S). These species are converted in a Claus reactor to elemental sulfur, which is sold as a by-product.

Small-scale process tests have been conducted at the Tennessee Valley Authority's Shawnee Plant and at PETC. Parametric testing and corrosion experiments are currently being conducted in a 5-MW pilot plant at Ohio Edison's Toronto Plant. A 115-MW demonstration of the process will be conducted at Ohio Edison's Niles Station under the third round of the DOE Clean Coal Technology Program. Process uncertainties appear to be in the areas of NO_x-recycle performance, sorbent attrition rates, and materials corrosion in some parts of the system (14). A recent independent cost study estimated capital costs for the process at $257/kW (1990 dollars) with levelized costs of 11.7 mills/kWh (15).

SNRB Process

The SNRB (SO_x-NO_x-Rox-Box^{TM}) process of Babcock & Wilcox combines injection of an SO_2 sorbent with a hot catalytic baghouse for NO_x and PM removal (Figure 5). A calcium- or sodium-based sorbent is injected either upstream or downstream of the boiler economizer and reacts with SO_2 in both the duct and the filter cake on the bags. Ammonia (NH_3) injected into the flue gas reacts with NO_x over a catalyst suspended within the filter bags, producing N_2. A key process feature is the use of woven ceramic filter bags to withstand temperatures of 425-450°C. Low exit SO_2 and sulfur trioxide (SO_3) levels may permit lower air preheater exit temperatures and greater system thermal efficiency.

Laboratory pilot tests demonstrated 90% NO_x removal at 0.95-1.05 NH_3/NO_x molar ratios and 70% to 80% SO_2 removal for $Ca(OH)_2/SO_2$ stoichiometries of 2.0-2.5 (16). Future small-scale testing will assess other bag filter fabrics and the SO_2 removal capabilities of alternative sorbents. A 5-MW process demonstration will be conducted at Ohio Edison's R.E. Burger Plant under the second round of the DOE Clean Coal Technology Program. Construction of the facility has been completed and testing began in May 1992.

Development issues to be resolved include demonstration of satisfactory long-term performance for the integrated system, demonstration of high SO_2 removals at reasonable sorbent consumption, demonstration of economic filter bag and catalyst lifetimes, development of a control philosophy for response to load changes and system upsets, and verification of the enhanced heat-recovery capabilities. A thorough economic analysis of the process is not available, but a preliminary estimate by the developer put operating costs at about one-half those of a wet FGD/SCR system (17).

SNOX and DESONOX Processes

The SNOX (WSA-SNOX) process, developed by Haldor Topsøe A/S, is designed to catalytically remove 95% or more of both the SO_2 and NO_x in the flue gas while producing a salable by-product of concentrated sulfuric acid, as shown in Figure 6. Selective catalytic reduction of NO_x to N_2 using ammonia is followed by catalytic oxidation of SO_2 to SO_3. The SO_3 is hydrated to sulfuric acid, which is then concentrated to 95% acid strength in an air-cooled falling-film condenser constructed of glass. Although the process consumes a significant amount of energy, extensive energy recovery within the process is claimed to give net energy savings for the plant of 1-4% (1% for each percent of sulfur in the fuel), due mainly to the exothermic heat of formation of sulfuric acid (18). Ammonia slip from the SCR reactor is oxidized in the SO_2 converter and does not present an emissions problem. A baghouse or ESP upstream of the SCR unit removes most PM. Any remaining fine particulates are retained in the SO_2 converter catalyst bed, which undergoes periodic cleaning by means of a semi-automatic system for sifting the catalyst. Lifetimes of 7-10 y for the SO_2 catalyst and 3-6 y for the NO_x catalyst are projected at this time on the basis of previous tests (19).

In Denmark, a 3-MW process demonstration unit operated on a low-sulfur flue-gas stream from 1987 until 1991, and a 300-MW full-scale SNOX plant began operation in November 1991 on a boiler firing medium-sulfur (1.6%) coal. A 30-MW unit has been in operation on a petroleum-coke-fired boiler in Italy since April 1991. That unit has maintained greater than 96% NO_x removal and over 96% SO_2 removal (20). In the United States, a 35-MW demonstration of the technology will be conducted at Ohio Edison's Niles Station under the second round of the DOE Clean Coal Technology Program. Asea Brown Boveri (ABB) has completed the facility construction, and shakedown is currently being conducted. An independent study evaluating NO_x/SO_2 technologies according to EPRI guidelines estimated process capital costs of $375/kW and a levelized cost of 10.5 mills/kWh (1990 dollars) (15).

A similar process called DESONOX was conceived by the German firm Degussa and is being developed jointly with Stadtwerke Münster, Lentjes, and Lurgi. A single reactor tower containing both reduction and oxidation catalysts is used. The sulfuric acid by-product is claimed to be of sufficient purity to be used in producing fertilizers. The process has been demonstrated on a 98-MW boiler at the Hafen cogeneration plant in Münster since November 1988; a second unit is planned to go into operation at the same facility in the summer of 1992. Removals for low-sulfur coal operation have been approximately 80% for NO_x and 94% for SO_2 (21).

Copper Oxide Process

The copper oxide (CuO) process developed at PETC combines SO_2 capture with catalytic reduction of NO_x using NH_3 in a single fluidized-bed reactor containing a CuO-impregnated alumina sorbent (Figure 7). Regeneration of the sorbent using a reducing gas produces a concentrated SO_2 stream that can be processed into a salable by-product. Small-scale tests have yielded approximately 90% removal of both species (22). Under DOE contract, UOP is to complete a conceptual design and economic evaluation of a 500-MW commercial-scale unit. Previous estimates have placed capital costs at $177/kW (1984 dollars), with levelized operating costs of 20.3 mills/kWh (23). A moving bed variation on the process, developed by Rockwell International Corp., also removes PM and is scheduled for small-scale testing at PETC.

E-Beam Process

Irradiation of flue gas with high-energy electrons initiates chemical reactions that oxidize SO_2 to SO_3 and NO to NO_2, which can be further reacted with a suitable base to form solid salts. An E-beam process being developed by Ebara (Figure 8) demonstrated removals of over 90% and 80% for SO_2 and NO_x, respectively, in a 5-MW pilot plant. Using NH_3 as a base, an ammonium-sulfate/ammonium-nitrate by-product with potential value as an agricultural fertilizer was produced. A similar process developed by Research-Cottrell using lime rather than ammonia as the base achieved removals of 90% for SO_2 and 60% for NO_x in pilot-scale tests. Ebara is currently investigating the concept of zone irradiation to achieve high efficiencies at lower total dose rates. It is hoped that this will reduce the process energy use by about one-third, to no more than 2% of the plant's gross output (24). Other commercialization issues include uncertainties regarding by-product utilization and economic scaleup of the electron-beam guns. One economics study puts process capital cost at about $400/kW (1990 dollars) and levelized costs at about 13 mills/kWh, although both values could be significantly reduced with successful development of the zone-irradiation concept and favorable by-product economics (15).

Activated-Coke Process

Activated coke can both adsorb SO_2 and catalyze the reduction of NO_x by ammonia. The use of two sorbent beds allows optimization of removal for each species, as shown in Figure 9. Regeneration of the spent sorbent at high temperature produces a concentrated SO_2 stream that can be further processed to yield a salable by-product, such as sulfuric acid. Such systems have been applied commercially by Bergbau-Forschung GmbH (now Deutsche Montan Technologies) and others in Japan and Germany, where SO_2 removals of 90-99% and NO_x removals of 50-80% have been reported (25). However, most experience has been with low- to medium-sulfur systems, and there is some question regarding process suitability for high-sulfur systems because of high coke consumption. Capital costs of $220-240/kW have been projected for a 500-MW system in the United States firing medium-sulfur coal (26). However, no operating costs were reported.

Recently, the Electric Power Development Co. Ltd. of Japan has been investigating a single moving-bed activated char process for application to NO_x removal and SO_2 removal "polishing" on a fluidized-bed combustion system. Pilot-scale tests have given removals of over 80% for NO_x and 90% for SO_2. Development issues appear to include the char loss rate, start-up temperature response of the char bed, and negative effects of high moisture and SO_2 levels on NO_x removal (27).

Parsons Process

Very high levels of SO_2 and NO_x removal (up to 99%) are the objective of the Parsons Process. Simultaneous catalytic reduction of SO_2 to H_2S and NO_x to N_2 occurs in a hydrogenation reactor using steam-methane reformer gas, as shown in Figure 10. The resulting H_2S is recovered and processed to produce elemental sulfur, a marketable by-product, through the combination of two commercial technologies (FLEXSORB and Recycle Selectox). The performance of the catalytic hydrogenation reactor has been tested with high-sulfur coal in a pilot plant at the St. Marys Municipal Power Plant in Ohio. Results showed that SO_2 reduction of 98+% and NO_x reduction of 92-96% were achievable (28). Although the long-term performance of the catalyst in a particulate-laden gas stream is unknown, a two-day test with high dust loading in the flue gas showed no change in the performance of the catalytic SO_2 and NO_x removals and no plugging of the honeycomb catalyst openings (28). On the basis of EPRI economic procedures, projected capital costs for a 500-MW plant are $285/kW (1982 dollars) and levelized busbar costs are about 26 mills/kWh (29). A significant process development issue may be the effects of flue-gas O_2 content on increasing hydrogen consumption and, hence, operating costs.

Other NO_x/SO_2 Control Technologies

Other NO_x/SO_2 control technologies undergoing development, but for which limited information is available, are described below.

The SOXAL™ process is a regenerable sodium-based scrubbing system coupled with urea/methanol injection in the boiler with the goal of 90% SO_2 and NO_x removal. A sodium-sulfite scrubbing solution absorbs SO_2 and is regenerated by an electrochemical process using bipolar membranes. Urea reduces 50-70% of the NO to N_2, and methanol oxidizes the remaining NO to NO_2, which is then removed in the sodium sulfite scrubber. A 3-MW pilot facility will be operated by Aquatech, a division of Allied-Signal, at the Niagara Mohawk Power Corporation's Dunkirk Station under a demonstration program initiated in September 1991 (30).

The Sorbtech (formerly Sanitech) Mag*Sorbent process uses magnesia-coated expanded-vermiculite granules for 90% SO_2 removal and moderate levels (30-40%) of NO_x removal (31). The flue gas is humidified upstream of a radial panel-bed filter containing the dry magnesia (MgO) to within a 30°C approach to the adiabatic saturation temperature. The sorbent is regenerated at 600°C with air or a reducing gas. A 2.5-MW pilot plant has been installed at Ohio Edison's Edgewater Station and was undergoing shakedown tests in late 1991 (32).

The Lively Intensified Lime-Ash Compound (LILAC) process is being developed by Hokkaido Electric Power Co. and Mitsubishi Heavy Industries Ltd., both of Japan. The process uses a sorbent that is produced by hot-water curing of a mixture of fly ash, lime, and gypsum for about 12 hours. The sorbent can be sprayed as a slurry into a spray-dryer vessel or as a powder into the flue-gas duct. The resulting solids are collected in either a baghouse or an ESP downstream of the injection point. Bench-scale tests of the slurry process gave SO_2 and NO_x removals of about 90% and 70%, respectively. When seawater was used in the curing process, SO_2 removals up to 95% were obtained. A pilot-scale facility is now under construction, with operation scheduled to begin in 1993 (33).

A dry FGD process using a circulating fluidized-bed reactor has been in commercial operation on five coal-fired utility boilers in Germany since 1987, and a combined NO_x/SO_2 version of the process is currently under development. It uses a hydrated lime sorbent for SO_2 capture and an unsupported $FeSO_4$ catalyst plus ammonia for reducing NO_x. Typical operating temperatures are on the order of 385°C, requiring placement of the absorber upstream of the air preheater. Pilot-plant tests on a low-sulfur system (inlet SO_2 concentrations of 450-630 ppm) gave SO_2 removals up to 97% for Ca/S mole ratios of 1.6-1.8. Removals of NO_x up to 88% were achieved with an NH_3/NO mole ratio of 0.7 (34). High sorbent recycle rates (up to 98%) are used in the large-scale FGD systems, but no data were reported for catalyst recycle or loss rates in the pilot plant.

The SONOX^{TM} process was developed at Ontario Hydro Research Corporation and has been licensed to Research-Cottrell Cos., Inc. It involves in-furnace injection of a slurry consisting of lime or limestone for SO_2 capture plus a nitrogen-based additive (such as urea) to control NO_x. Reaction products are captured in a downstream PM collector. Calcium to sulfur mole ratios of 2-3 are expected, together with 1.5-2 moles of NO_x-control chemical per mole of NO_x. Pilot-scale tests have been conducted in Canada, giving performance projections for a full-scale unit of 60-70% SO_2 removal and 50-60% NO_x removal. Currently, capital costs are estimated at $50-150 per KW and operating costs could be 3-4 times higher than those for wet FGD (35).

SUMMARY

There is an increasing probability that flue-gas cleanup for NO_x removal will be required at some installations in the United States. If that is the case, integrated systems that combine control functions in a single process offer a number of advantages for both retrofit and new situations. In recent years, considerable progress has been made in developing and characterizing a number of such systems, and new concepts continue to emerge from the laboratory.

The variety of concepts under development provides many technical and economic options to system designers:

- Retrofit versus totally new systems
- Tradeoffs between cost and removal capabilities
- Tradeoffs between SO_2 and NO_x removals
- Salable by-products versus throwaway waste

The spectrum of possibilities is certainly challenging to those who must sort through and evaluate the options on the way to a multi-million dollar technology selection. On the other hand, this same spectrum will make it possible to tailor an optimal energy/environmental system for the unique site and business characteristics of any particular installation.

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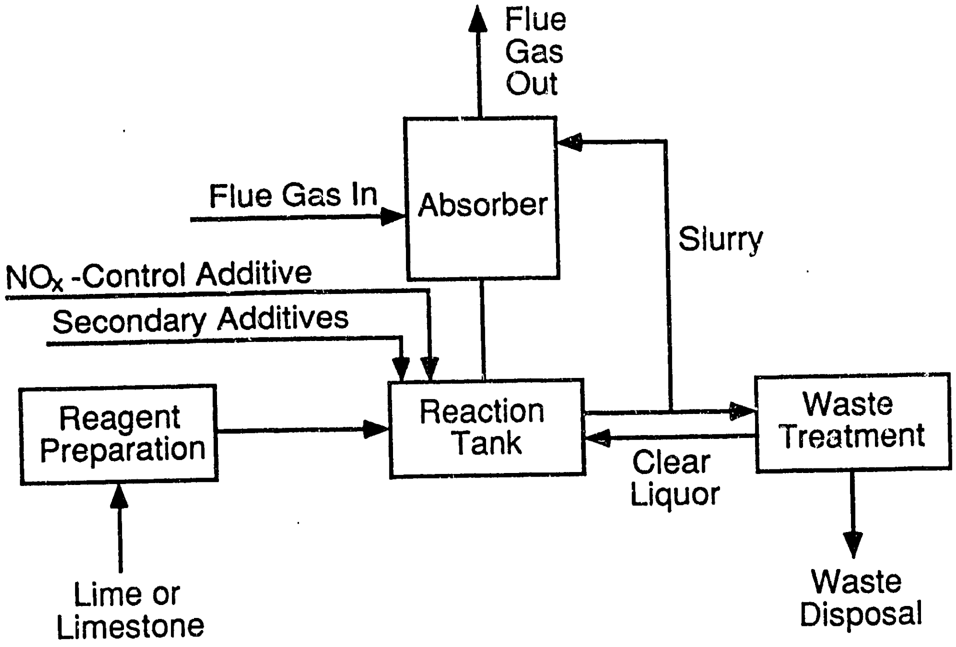

Figure 1. Wet FGD/Metal-Chelate Process

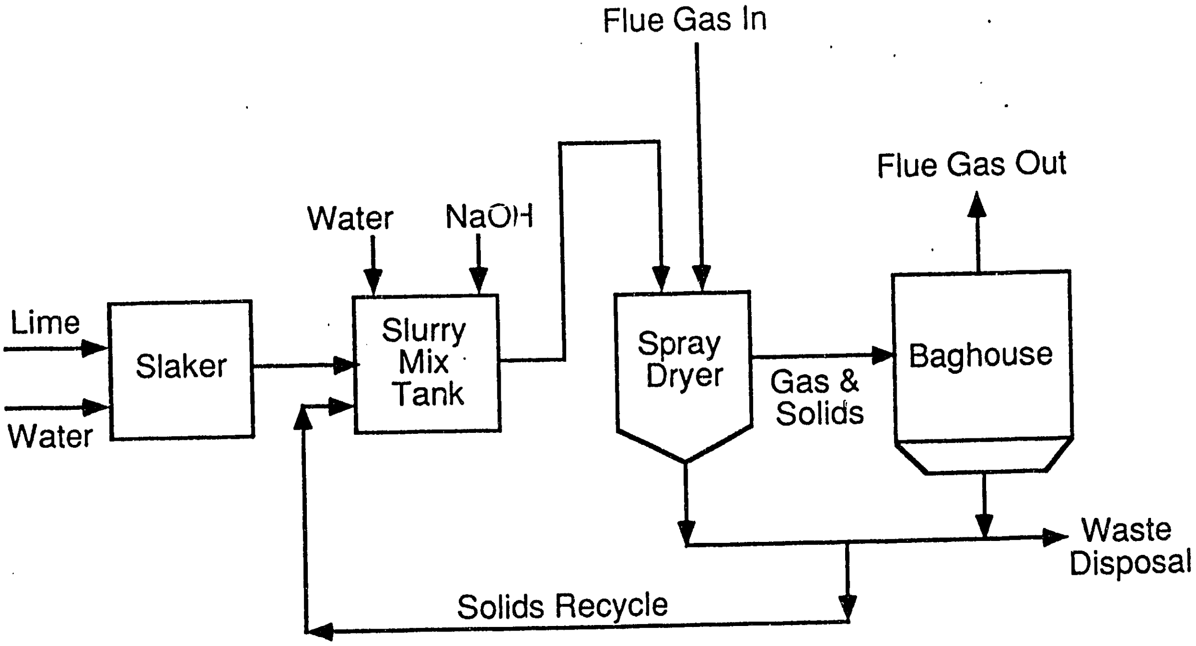

Figure 2. Modified Spray-Dryer Process

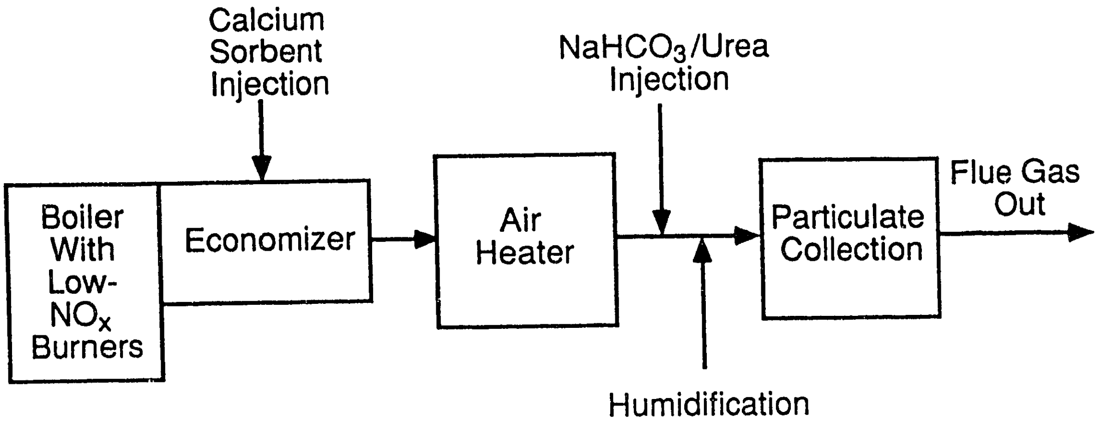

Figure 3. Integrated Dry-Injection Process

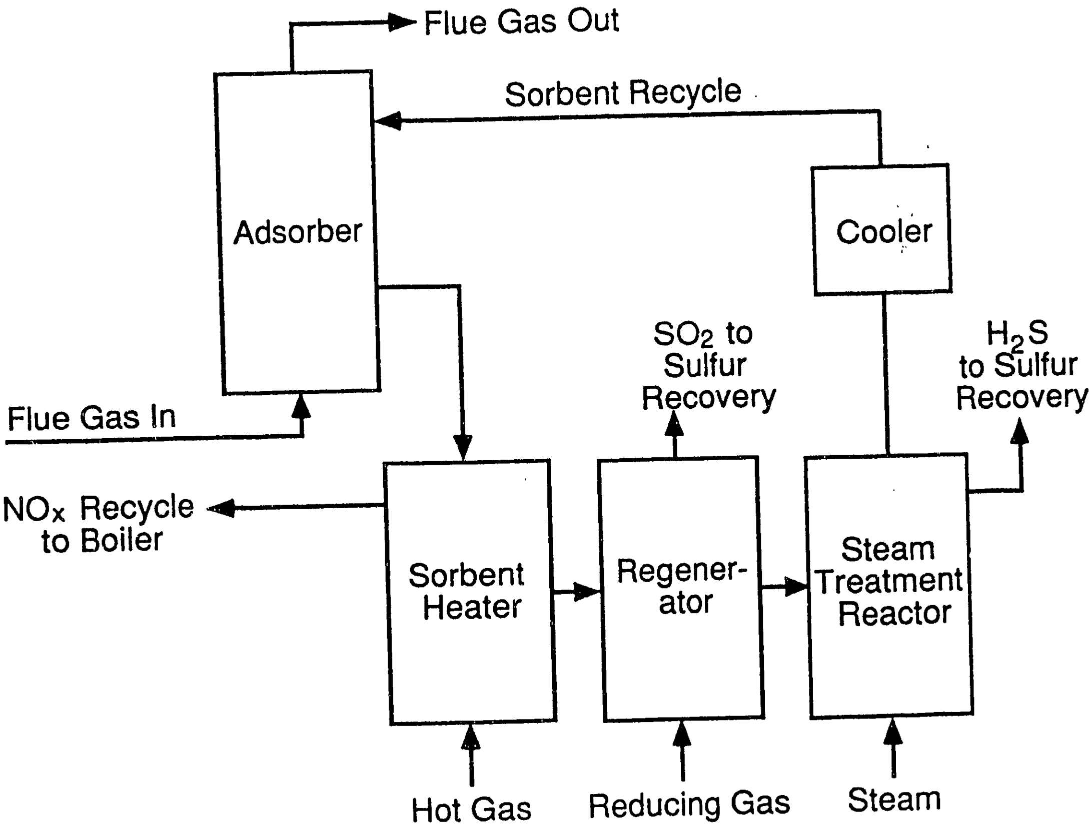

Figure 4. NOXSO Process

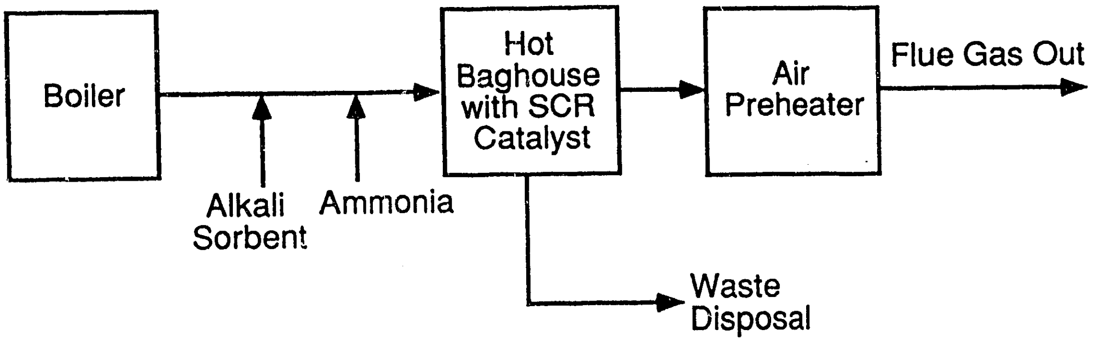

Figure 5. SNRB Process

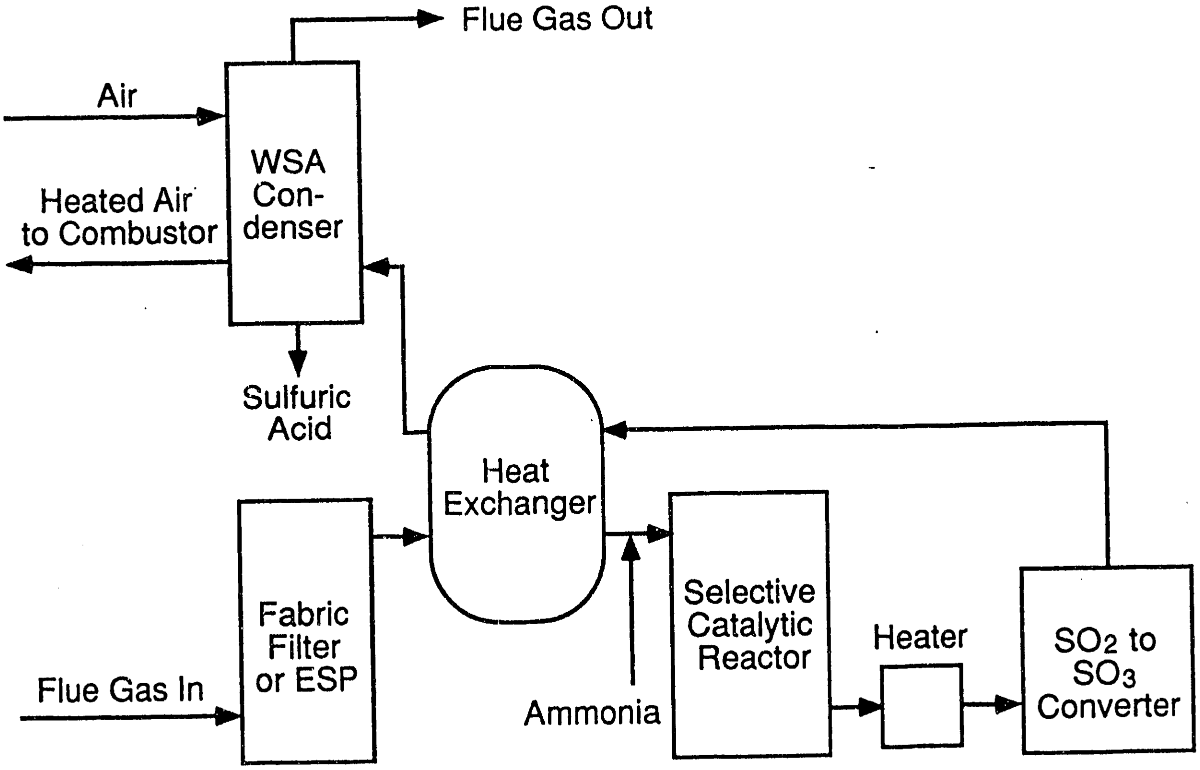

Figure 6. SNOX Process

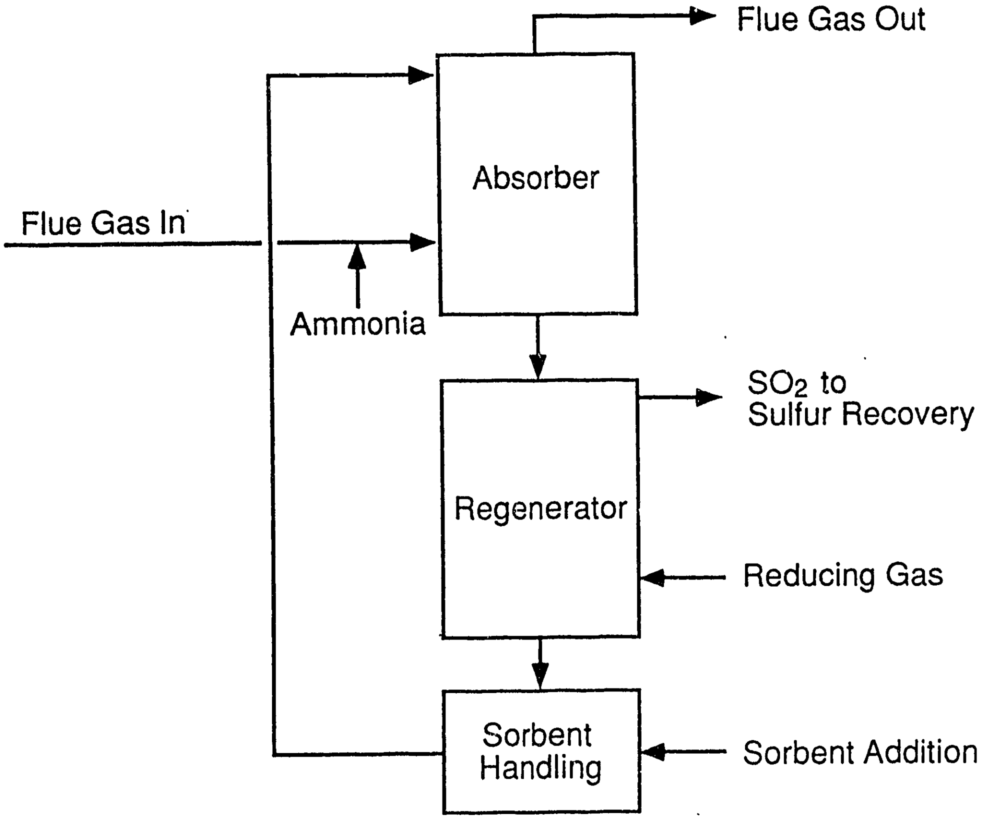

Figure 7. Fluidized-Bed CuO Process

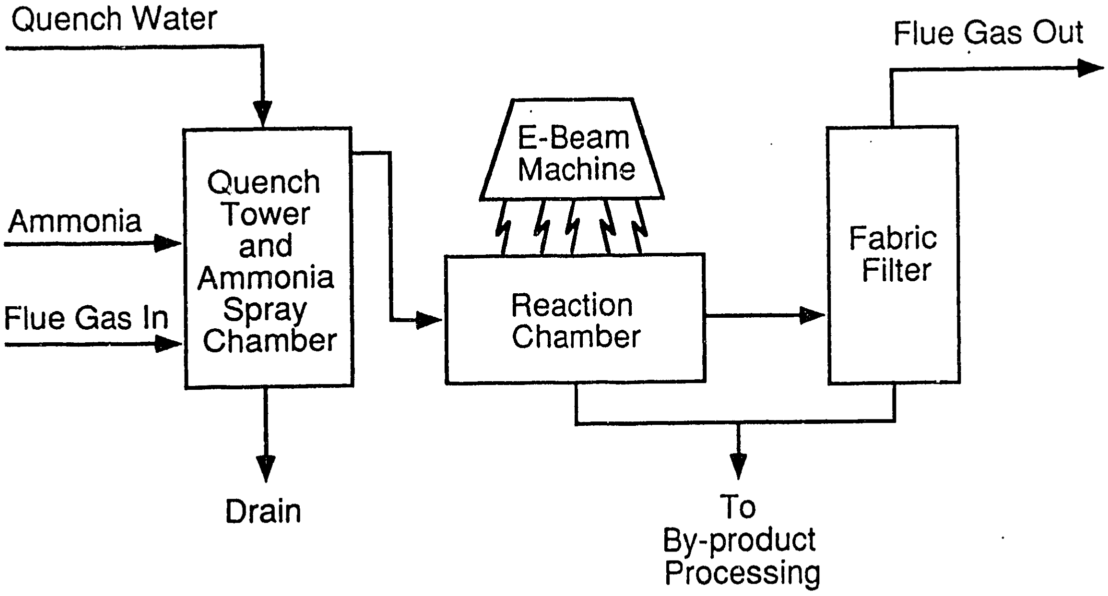

Figure 8. E-Beam/Ammonia Process

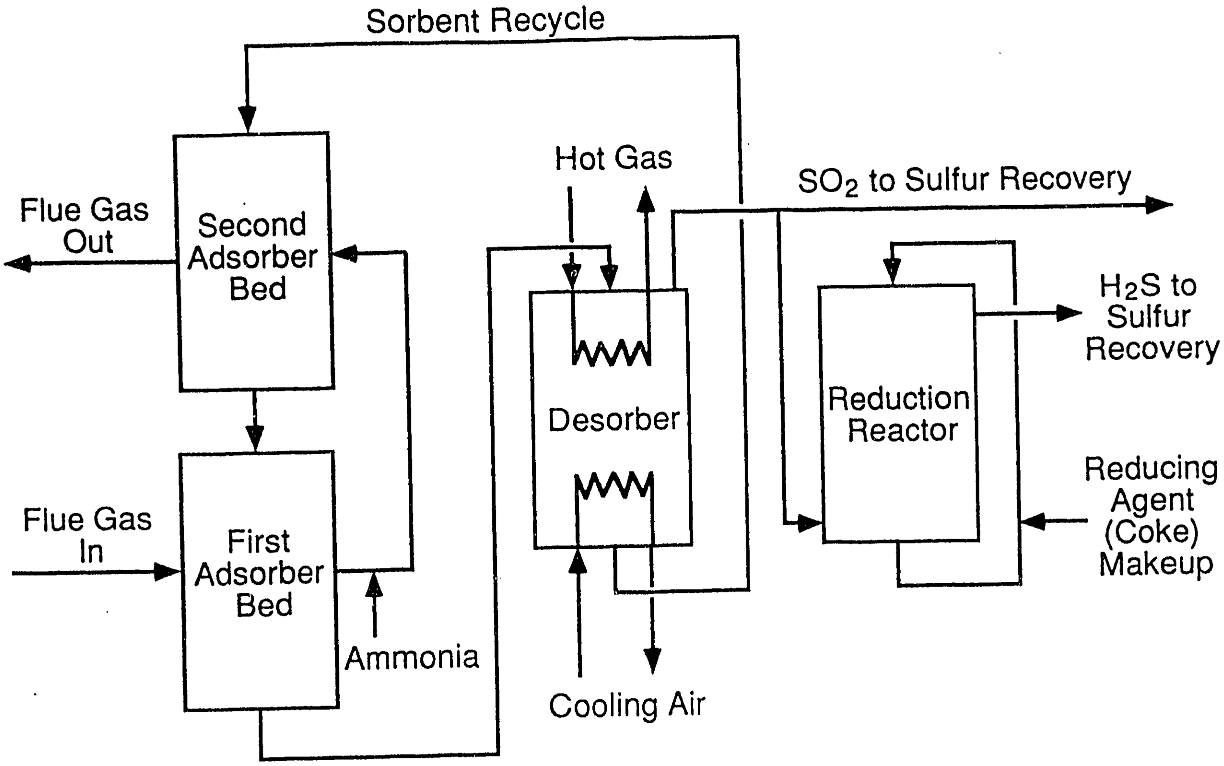

Figure 9. Dual-Bed Activated-Coke Process

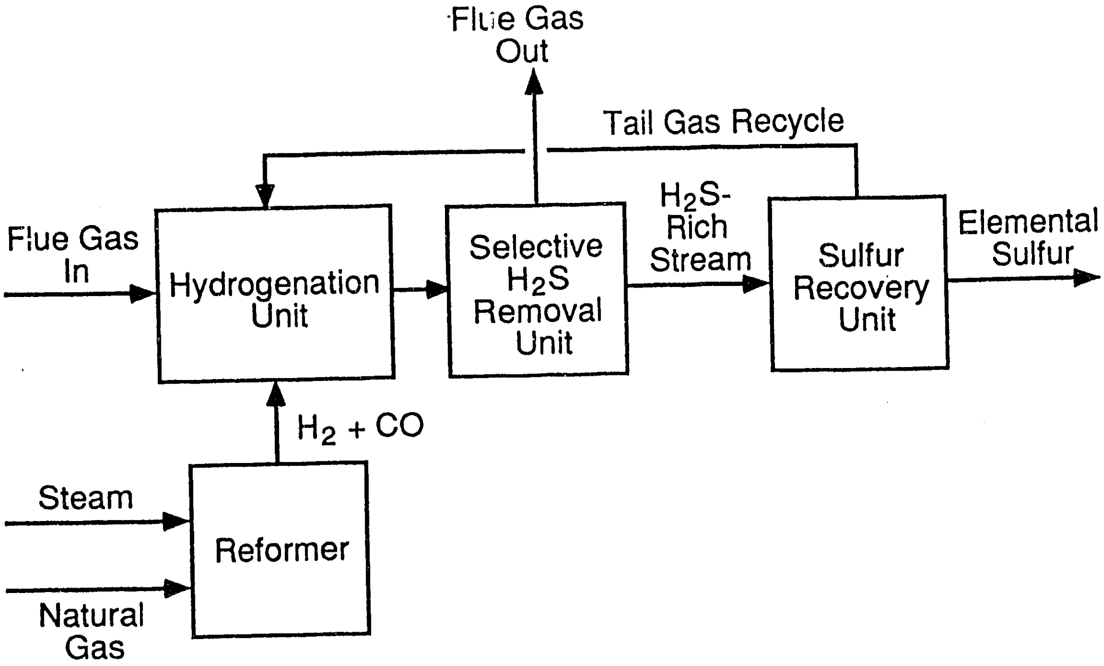

Figure 10. Parsons Process

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