

EVALUATING SULFUR-PRODUCING FGD PROCESSES

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Flue gas desulfurization systems can be broadly categorized as throwaway and recovery systems. In the throwaway systems, the sulfur removed from the flue gas is rejected from the process in a waste sludge, usually a wet mixture of CaSO_3 and CaSO_4 . In recovery systems, the sulfur-absorbing reagent is regenerated for recirculation to the flue gas contacting device while the sulfur removed from the flue gas is converted into its elemental form or into sulfuric acid. The dominant choices for commercial installations up to this time have been the wet, throwaway (lime/limestone) systems. Accordingly, the selection of these systems has been well-described in many symposia and other publications. However, the continued development of recovery processes has brought several to the commercial or near commercial status. Thus, this paper addresses the evaluation of such recovery processes for a commercial installation.

PROCESS DESCRIPTIONS

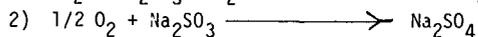
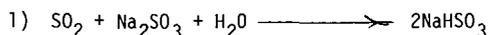
Three processes have been selected for discussion and comparison: Wellman-Lord/Allied Chemical sodium-based (commercial, wet), Catalytic/IFP ammonium-based (near commercial, wet), and Atomics International ACP (developmental, semi-dry). The Wellman-Lord process with Allied Chemical regeneration and the Catalytic/IFP process both require a clean reducing gas to carry out the regeneration of the absorbent and the production of elemental sulfur. Due to the limited availability of natural gas, the use of a medium Btu gas from a coal gasifier has been assumed for the comparison here and a gasifier included in each of these processes. The Atomics International ACP process can utilize petroleum coke or coal for its regeneration and reduction steps with the choice dependent upon their relative cost at a given site.

Wellman-Lord/Allied Chemical Process

The Wellman-Lord process consists of three major sections for SO_2 recovery: (1) scrubber, (2) evaporative-crystallizer, and (3) sodium sulfate removal. The Allied Chemical SO_2 Recovery Process consists of a catalytic reduction of SO_2 to elemental sulfur.

The chemistry of the Wellman-Lord /Allied Chemical process is as follows:

Absorber:



Evaporator:



Reducer:



Figure 1 shows a block diagram of the coupled scrubbing-regeneration system.

Flue gas from the electrostatic precipitator is adiabatically saturated with water, then contacted countercurrently with the absorbing solution. Sulfur dioxide is absorbed into the solution of sodium sulfite and reacts to form sodium bisulfite as

shown in reaction 1. The scrubbing solution is recirculated through the scrubber to obtain a concentrated solution of bisulfite. Reaction 2 also occurs during scrubbing and recirculation to form the unregenerable by-product, sodium sulfate. Reaction 1 is reversed in an evaporative crystallizer where sodium sulfite is crystallized and SO₂ and water are released as gases (Reaction 3). Steam is used to decompose the bisulfite at the rate of 9-12 pounds of steam per pound of SO₂ recovered. A purge stream is taken to prevent build-up of sodium sulfate. The regenerated sulfite is returned to the scrubber (1).

The product of the Wellman-Lord Process is a stream of concentrated SO₂. The SO₂ may be oxidized to produce sulfuric acid or it may be reduced to elemental sulfur in any number of processes. The Allied Chemical SO₂ Reduction Process (2) can utilize reducing gas to produce sulfur via reactions 4 and 5. These reactions take place at high temperature, requiring refractory-lined reactors.

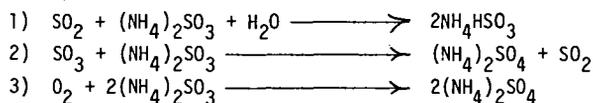
Commercial Status. The Wellman-Lord process is fully commercial with numerous installations world-wide, largely on oil-fired boilers. The Allied Chemical SO₂ reduction process has been operated commercially at a large Canadian copper smelter. A 100 MW demonstration plant has recently been started up at NIPSCO (3).

Catalytic/IFP Ammonia Scrubbing Process

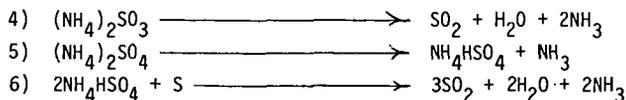
The Catalytic/IFP process consists of five major process sections: (1) scrubber, (2) evaporator-decomposer, (3) sulfur dioxide reduction, (4) reducing gas generation, and (5) wet Claus sulfur recovery. A block diagram of the IFP process is shown in Figure 2.

The chemistry of the IFP process is as follows:

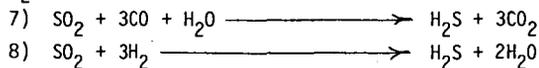
Absorption:



Regeneration:



H₂S Generation:



Claus Reaction:



The flue gases from the electrostatic precipitator are first adiabatically saturated with water in the bottom section of a tray tower. The saturated gases are then contacted with an ammonium sulfite brine to remove sulfur oxides. Reactions 1, 2, and 3 take place in the scrubber. Before the gases are discharged from the scrubber, they are washed in an additional stage with water (or acid) to remove residual gaseous ammonia to prevent its loss. A stream of concentrated

brine is removed from the bottom of the scrubber and sent to an evaporator which separates out ammonium sulfate crystals and decomposes the sulfites to NH_3 , SO_2 , and H_2O by reaction 4.

The sulfate crystals from the evaporator are decomposed in a reducing atmosphere by reactions 5 and 6. The heat for the reduction is supplied by submerged combustion of medium Btu gas with a deficient amount of air. The reduction takes place at 600-700°F.

Additional medium Btu gas is supplied to reduce the stream from the evaporator. Two-thirds of the sulfur dioxide is reduced to hydrogen sulfide by reactions 7 and 8. The hydrogen sulfide produced in the SO_2 reducers and the remaining SO_2 are reacted in the IFP "wet Claus" reactor by reaction 9 to form elemental sulfur. Ammonia is recovered and unreacted H_2S is incinerated or returned to the power plant boiler to be oxidized to SO_2 (4).

Commercial Status: IFP has studied all the single processing steps on the laboratory and pilot scale at their research center in France. A fully integrated 30 MW demonstration is now operational on an oil-fired utility boiler in France (4). Catalytic is now operating an engineering optimization unit on flue gas from a coal fired utility boiler at an Air Products chemical plant in Kentucky.

Atomics International - Aqueous Carbonate Process (ACP)

The ACP consists of four major sections: (1) scrubber, (2) reducer, (3) carbonator, and (4) Claus plant. Figure 3 shows a block diagram of the ACP.

The chemistry of the ACP is as follows: (5)

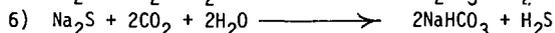
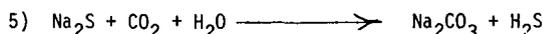
Scrubber:



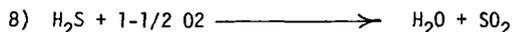
Reducer:



Carbonator:



Claus:



The flue gas leaving the electrostatic precipitator is contacted by sodium carbonate solution to remove sulfur oxides by reactions 1 and 2. These reactions take place in a modified spray drier which is unique to the ACP. The scrubbing solution is dispersed into a finely atomized fog which flows concurrently with the flue gas down the spray drier. The sulfur dioxide from the flue gas diffuses into the liquid phase of the solution and reacts. Water simultaneously evaporates from the tiny fog droplets.

At the bottom of the spray drier, all of the water has evaporated from the "scrubbing" solution and the flue gas has been cooled to a minimum of 20°F above its water saturation temperature (usually 150°F to 200°F). The solids created by the evaporation of the water are collected, first mechanically and then with an electrostatic precipitator. The flue gas is then discharged to the atmosphere through a stack (5).

The solids from the spray drier are conveyed into a molten salt reactor where the reduction reactions 3 and 4 occur. Excess coke or coal is fed to the reducer and the temperature is maintained at 1800°F by combustion of carbon with air. Petroleum coke is presently preferred in the ACP (5), but coal has been successfully tested.

The molten sodium sulfide (Na_2S) product of the reduction is quenched in water and filtered to separate residual solids (carbon and fly ash). The sodium sulfide solution is converted to sodium carbonate by reactions 5 and 6. The CO_2 for H_2S stripping is recovered from the CO_2 rich off-gases from the reducer. The bicarbonate is thermally decomposed and the CO_2 returned to the carbonation step (reaction 7). Sulfur is recovered from the hydrogen sulfide in a standard Claus Plant.

Commercial Status. Atomics International has piloted the spray drier in a 7 ft. I.D. unit with a simulated flue gas and also with a 5 ft. I.D. unit on real flue gas at the Mohave Station. The molten reduction of sodium sulfide and sulfate has been carried out in a 3 ft. I.D. reactor. The A.I., carbonation process has been operated at bench scale. (Equivalent to about 1 MW.) These process steps have not been tested in closed loop operation, but successive use of the product from each individual step through the entire sequence has been carried out.

EVALUATION FACTORS

A review of the detailed flowsheets and material and energy balances (1), for these processes shows differences in energy consumption, type of reducing agent required, and the degree of interaction with the operation of the boiler. In addition, especially for new technology, the extent of technical risk for each process is also a key evaluation factor. Two of these factors are amenable to quantitative evaluation: energy consumption and type of reducing agent. The other two are subjective and can only be quantified by intuitive technical judgement. For example, on a scale from 0 to 10 points, the use of coal as the reducing agent might be given 10 points and natural gas, 0. In another category, a fully commercial process might score the full amount allowed while one under development might only score 20-30% of the full amount. The number of points awarded for the maximum in each category must be determined for each specific site. The availability of the various reducing agents, water, power, land area and intangible attitudes toward technical risk and modifications of normal operations must all be considered. The limitations on the method reflect the uncertainties and risks in evaluating evolving technology. However, the effort and discipline involved in performing such an evaluation can lead to consistent results among independent evaluators.

The amount of energy consumed by an FGD process has a direct impact on the power plant's heat rate (efficiency) and also on the available net electric generating capacity. If a utility must purchase power to offset that consumed by an FGD process it may prefer to select an alternative with higher fuel consumption and lower electrical demand. Such a sacrifice of efficiency for capacity may also be justified where costly peak generating would be required to supply the power consumed by the FGD process. These considerations would be reflected in the choice of maximum score assigned to this factor.

The preferred reducing agent for any process would be the same coal used as boiler fuel. This would ensure an adequate supply and eliminate any requirement for special purchasing, handling and storage. The choice of coal as the preferred reducing agent imposes a direct

penalty for processes unable to use it. It also imposes an indirect penalty in the added technical risk, higher cost, and higher fuel consumption required by a coal gasifier. The extent of such penalties is obviously very site-dependent.

The lesser the extent of interaction between the FGD process and the boiler, the more preferable, because it minimizes operating problems. However, a by-pass for flue gas around the FGD system must be installed and permission obtained to use it when necessary, or this factor is not a valid consideration. Interaction involves the pressure drop through the absorber, as it poses a potential threat of back-pressure in the boiler in case of plugging the absorber or failure of the ID fan. The interaction can also be reduced by providing sufficient intermediate storage to allow limited operation of the absorber while the regeneration section is out of service and vice versa.

The evaluation of technical risk and the weight given to it in the total evaluation is likely to reflect the troubled operating histories of all FGD installations to date, even those which are now successful. The newness of the sulfur-producing processes emphasizes the need to carefully consider redundant components and the materials of construction chosen for the severe service encountered in the regeneration sections. Initial designs are likely to be conservative in attempting to achieve mechanical reliability and minimize the technical risk. The extent to which this is carried out will be limited by cost and by the reliability requirements of the prospective host utility.

Other site-specific evaluation factors are shown in Table 1. The amount of sulfur to be

Table 1

SITE-SPECIFIC EVALUATION FACTORS

% S in coal (% removal required)

% Ash in coal (% removal required)

Other state and local regulations

Waste disposal

Water quality and availability

Geographic factors (elevation, ambient temperature range, etc.)

removed depends upon the sulfur content of the coal and the emissions control requirements. All of the processes under active development should be capable of meeting all current SO₂ emissions limits. The flyash must be removed to prevent operating problems in the FGD system and to meet emissions limits. Unlike the lime/limestone systems, regenerative FGD processes cannot tolerate ash-laden flue gas. Limitations on liquid and solid waste streams can have a major impact on the feasibility of processes such as these with their purge streams. Sufficient water must be available for the consumptive needs of these processes. In addition, it must be of adequate quality to vaporize and disperse into the atmosphere. Local geographic factors influence the size of equipment and the extent of insulation and protective structures required. These all have differing impacts on the evaluation of individual processes.

APPLICATION OF THE EVALUATION METHOD

To illustrate the foregoing evaluation method for the processes described earlier, a hypothetical site for a new 500 MW utility boiler was selected with the characteristics shown in Table 2. The values chosen for the boiler, coal and site are intended to be representative of a wide range of actual conditions. The emissions limitations for particulates must be controlled, since all three regenerable processes require prior

removal of fly ash to prevent interference with process chemistry and process equipment.

The SO₂ removal to meet New Source Performance Standards (NSPS) of 1.2 lb SO₂/MMBtu is about 80%, if all the sulfur in the coal emerges as SO₂. (In many cases 10-15% of the sulfur remains in the bottom ash.) Each of the three processes described earlier should easily meet this requirement.

The assumed plant characteristics of no natural gas and a premium for petroleum coke tend to impose realistic penalties for special reducing agents. For both Catalytic/IFP and Wellman-Lord/Allied Chemical processes, a coal gasifier is required to supply an acceptable reducing agent and fuel. This increases the complexity and cost of these processes. The presence of plentiful water eliminates any penalty for consumptive use in the FGD processes.

The Wellman-Lord/Allied Chemical process with a 60% efficient gasifier consumes about 50,000 Btu/pound of elemental sulfur produced (1). The Atomics International ACP process consumes about 28,000 Btu/pound of elemental sulfur produced (5). An evaluation of the Catalytic/IFP process for this study showed comparable electrical and reheat demands to those for the Wellman-Lord. However, steam and reductant consumption should be lower with the total energy required for Catalytic/IFP intermediate to the other two processes.

For all three processes, coal is the reductant. However, the need for a gasifier in the Wellman-Lord/Allied Chemical and Catalytic/IFP processes adds to their complexity and to their consumption of energy. Thus, the Atomics International ACP process has an advantage for this factor.

Since all three processes use clear solutions as sulfur-absorbing reagents, do not require hot precipitators, and should be capable of responding to boiler load changes, they all show satisfactory independence from the boiler. Nevertheless, the Catalytic/IFP and Wellman-Lord/Allied Chemical processes have relatively high pressure drops through their absorbers, require flue gas reheaters (which have poor reliability records), and use solutions which are more voluminous to store prior to regeneration than the solid product from the Atomics International absorber. Thus, an edge in evaluating this factor would go to the Atomics International ACP process.

As discussed in the preceding section, a prudent evaluation should place heavy emphasis on mechanical and chemical reliability. In this context, a relatively undemonstrated process, such as the Atomics International ACP, is penalized. The Wellman-Lord/Allied Chemical process is the best demonstrated, followed by the Catalytic/IFP process. They would receive correspondingly higher ratings for this factor.

In considering the site-specific evaluation factors (Table 1) for this hypothetical site, the major considerations are waste disposal and the impact of rather severe winters on these three processes.

The production of by-products by an FGD process can be troublesome. Both the Catalytic/IFP and Wellman-Lord/Allied Chemical processes have purge streams of wet flyash from the water used for humidification. The Wellman-Lord process has a further disadvantage in the generation of a sizable purge stream of sodium sulfate. Up to 10% of the SO₂ absorbed is oxidized to the unregenerable sulfate. In considering these factors, the Atomics International ACP process has an advantage, although a small purge of mixed salts will probably be required.

The relatively bulky spray-dryer type of absorber used in the Atomics International ACP process and the more stringent temperature control required for its proper operation will raise its cost for insulation and weather protection relative to the others. The several

solids transport steps required may also be troublesome in severe weather. Thus, both the Catalytic/IFP and Wellman-Lord/Allied Chemical processes should have an edge for this specific site.

Assigning numerical values to all of the pertinent factors described in the preceding section is, itself, a subjective problem. Local preferences and prior experience will weigh heavily in the choices made. For a hypothetical site (Table 2) and for only these three representative processes, this seems neither warranted nor instructive. It is a matter of agonizingly strenuous judgement to set up such a numerical table for a specific case. Once this is done, processes can be consistently evaluated at the cost of further effort in assigning individual scores.

For the three processes considered in the general framework here, the Wellman-Lord/Allied Chemical process has the advantage of being the best demonstrated. The Catalytic/IFP process is nearly as well demonstrated, uses less energy and produces less solid waste. The Atomics International ACP process is still under development, but has the potential to use coal as a direct reductant, to use the least energy of the three processes and to produce the least solid waste. Thus, incentives exist to continue to move both the Catalytic/IFP and Atomics International ACP processes toward commercialization.

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- (3) Mann, E.L. and Christman, R.C., "Status of Demonstration of the Wellman-Lord/Allied FGD System at NIPSCO's D.H. Mitchell Generating Station. Part I", FGD Symposium Sponsored by U.S. EPA, New Orleans, March, 1976.
- (4) Ennis, C.E., "APCI/IFP Regenerative FGD Ammonia Scrubbing Process", FGD Symposium Sponsored by U.S. EPA, New Orleans, March, 1976.
- (5) Gehri, D.C. and Oldenkamp, R.D., "Status and Economics of the Atomics International Aqueous Carbonate Flue Gas Desulfurization Process", FGD Symposium Sponsored by U.S. EPA, New Orleans, March, 1976.

TABLE 2

SAMPLE SITE CHARACTERISTICS

Plant Capacity:	500 MW
Capacity factor:	7,000 hrs/yr
Heat rate:	9,000 Btu/kwh
Flue gas rate:	3,100 ACFM/MW
Flue gas temperature:	310 ⁰ F
Eastern coal characteristics:	3.5% sulfur
	11,600 Btu/lb (as received)
Plant location:	Central U.S.
Plant characteristics:	Sufficient water
	No natural gas
	Petroleum coke available at a premium over coal
SO ₂ Emissions Limit:	1.2 lb/MM Btu (NSPS)

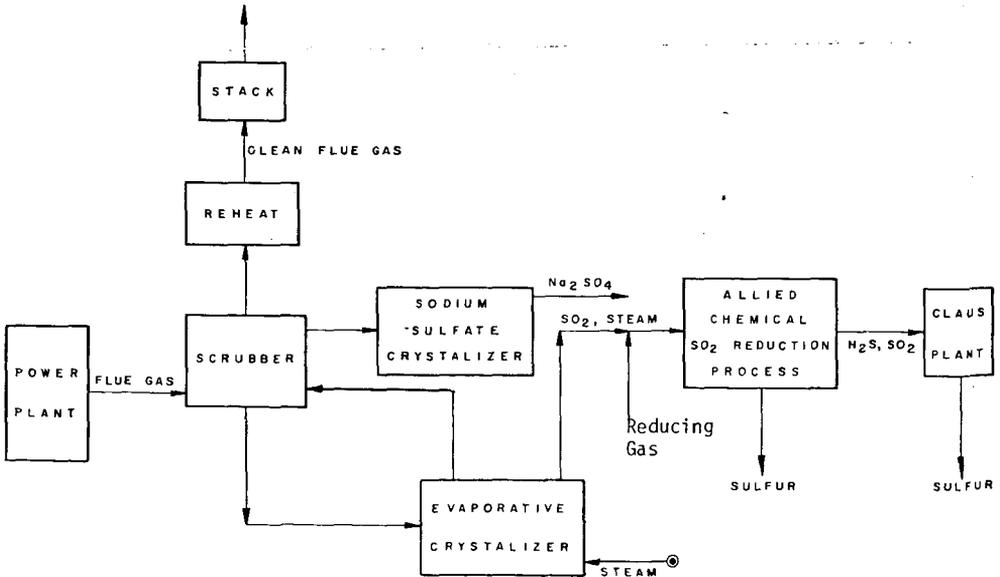


Figure 1. Wellman-Lord/Allied Chemical Process

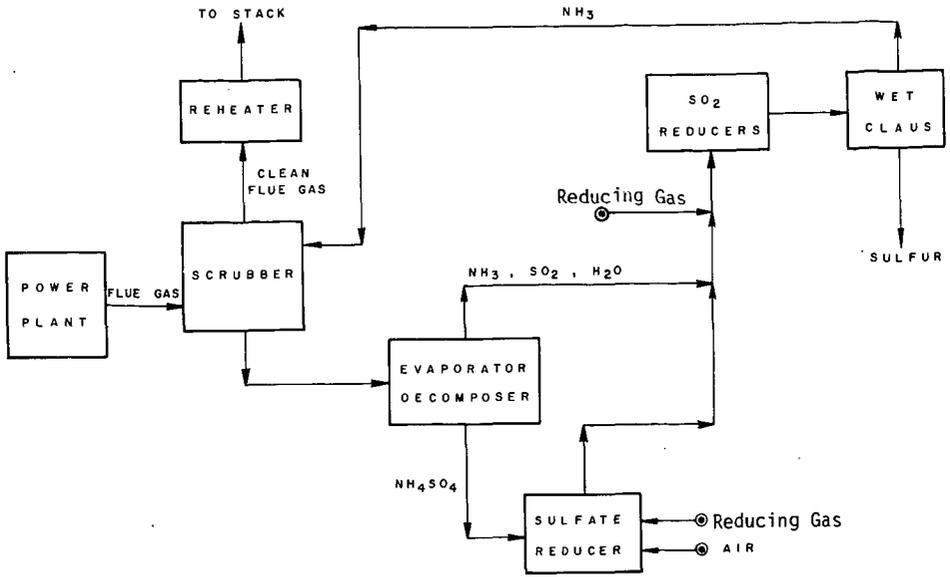


Figure 2. Catalytic/IFP Process

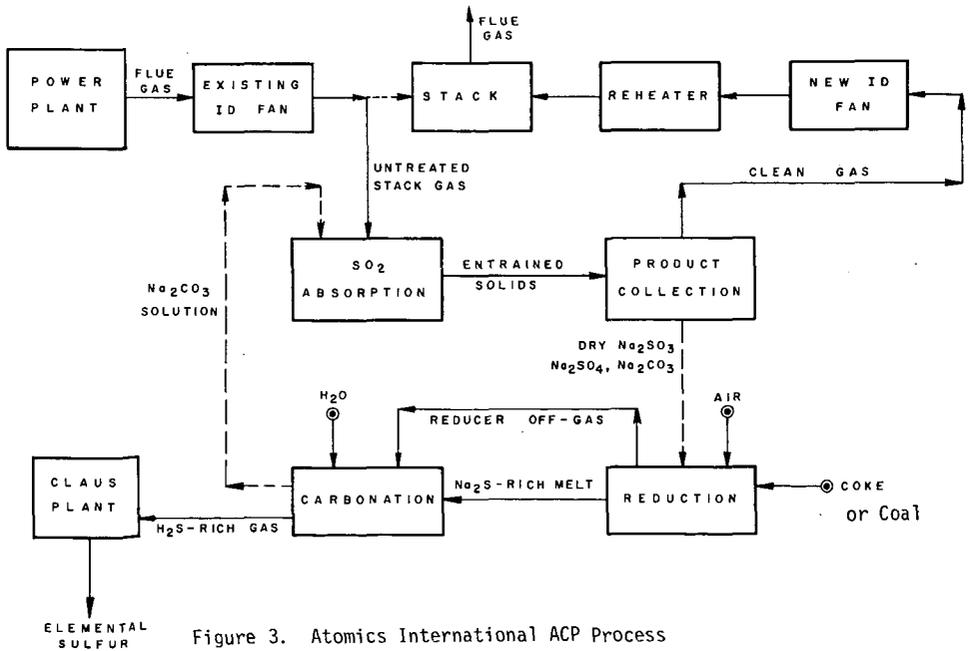


Figure 3. Atomics International ACP Process