

## *Project Summary*

# Impact of NO<sub>x</sub> Selective Catalytic Reduction Processes on Flue Gas Cleaning Systems

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Nitrogen oxide (NO<sub>x</sub>) emissions from electric utility boilers may be reduced by 80-90% through the application of pollution control technology based on the selective catalytic reduction (SCR) of NO<sub>x</sub> with ammonia (NH<sub>3</sub>); however, some unreacted NH<sub>3</sub> may be emitted from the control system. This study was performed to investigate the impact of the NH<sub>3</sub> leaving a NO<sub>x</sub> SCR process on downstream flue gas cleaning processes. These include electrostatic precipitator (ESP), baghouse, and flue gas desulfurization (FGD) systems. Under normal operating conditions, most of the NH<sub>3</sub> leaving the SCR system will be removed, either as particulate salts by the particulate removal system or as free NH<sub>3</sub> by the FGD system. Very little NH<sub>3</sub> should be emitted at the stack. The operation of ESP and FGD systems, in most cases, will be improved by the presence of NH<sub>3</sub> in the flue gas. The effects of NH<sub>3</sub> and NH<sub>3</sub> salts on baghouse operation are not known. At normally expected emission levels, no adverse environmental impacts are projected; however, at high NH<sub>3</sub> emission levels, the potential exists for problems with NH<sub>3</sub> in the waste streams from fly ash and SO<sub>2</sub> collection devices. Potential adverse environmental impacts exist in the ash and sludge ponds where collected NH<sub>3</sub> may be concentrated and emitted as a gaseous pollutant.

*This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).*

### Introduction

Recent Japanese experience with selective catalytic reduction (SCR) for controlling nitrogen oxides (NO<sub>x</sub>) emissions from gas- and oil-fired combustion sources has shown that NO<sub>x</sub> reductions of 80-90 percent are achievable.<sup>1,2</sup> Since this NO<sub>x</sub> reduction exceeds that of combustion modifications alone, the EPA is interested in demonstrating SCR technology in the U.S. The EPA has funded two pilot-scale demonstration projects for evaluating SCR process applicability to coal-fired combustion sources.

For a utility application of SCR (see Figure 1 for typical flue gas treatment configuration), the catalytic reactor is located between the economizer and air preheater sections of the boiler. At this point the flue gas temperature is 300-400°C (570-750°F) which is suitable for the NO<sub>x</sub> reduction reactions to occur rapidly. Ammonia (NH<sub>3</sub>) is injected into the flue gas upstream of catalyst and reacts with NO<sub>x</sub> on the catalyst surface to form elemental nitrogen and water. Steam is used as the carrier for the NH<sub>3</sub>.

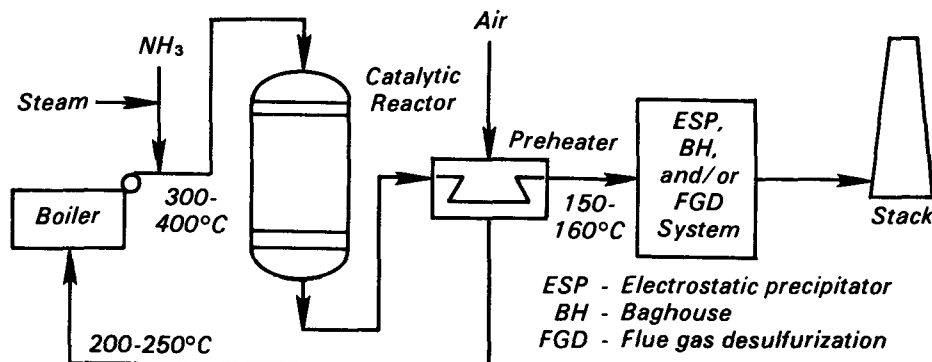
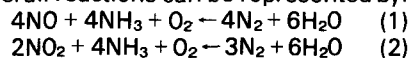


Figure 1. Typical arrangement—NO<sub>x</sub> SCR unit with boiler and other flue gas cleaning processes.

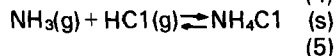
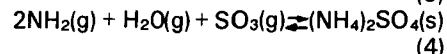
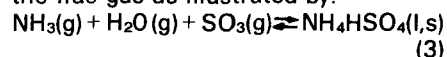
to aid in dispersion after injection. The overall reactions can be represented by:



Although SCR systems have undergone extensive commercial development in Japan, an unresolved issue is that of NH<sub>3</sub> emissions from the process and the impact of these emissions on equipment downstream of the catalytic reactor. Such equipment can include air preheaters, flue gas desulfurization (FGD) systems, and particulate removal devices. EPA has conducted two studies of the effects of excess NH<sub>3</sub> on downstream equipment. This report gives results of the study examining these effects on baghouse, ESP, and FGD systems. A separate investigation was conducted to examine the impact of excess NH<sub>3</sub> on air preheaters.<sup>(3)</sup>

### Problem Definition and Project Objectives

Unreacted NH<sub>3</sub> will exit the SCR system in concentrations normally expected to be about 10-20 ppm. However, under transient operating conditions, NH<sub>3</sub> levels may be higher. Ammonium sulfate salts can form in downstream equipment due to the reaction of NH<sub>3</sub>, SO<sub>3</sub>, and H<sub>2</sub>O present in the flue gas as illustrated by:



The direction in which these reactions proceed depends on the flue gas temperature and the concentrations of the reactants. At a given flue gas concentration, the formation of solid sulfate and liquid bisulfate will occur as the flue gas is cooled. For typical concentrations

of NH<sub>3</sub> and SO<sub>3</sub> downstream of an SCR unit, the approximate formation temperatures of (NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub> and NH<sub>4</sub>HSO<sub>4</sub> are 195°C-210°C and 165°C-180°C, respectively. Typical air preheater operating temperatures for the flue gas are from over 300°C at the inlet to about 150°C at the air preheater outlet. Obviously, the thermodynamics of the formation reactions indicate that some (NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub> and NH<sub>4</sub>HSO<sub>4</sub> can form in the air preheater. Some of these NH<sub>3</sub> salts will deposit on the preheater heat exchange surface, but most will pass through and enter the downstream particulate control equipment. Most of the particulates will be removed here, but unreacted NH<sub>3</sub> and traces of the NH<sub>3</sub> salts will continue into the FGD system.

The formation and deposition of ammonium sulfates in air preheaters has been observed downstream of SCR systems.<sup>(3)</sup> Deposits have also formed during tests of fly ash conditioning with NH<sub>3</sub> for improved ESP performance.

This study was performed to investigate the impact of the NH<sub>3</sub> leaving the NO<sub>x</sub> SCR process on downstream flue gas cleaning processes. Operational effects on ESP, baghouse, and FGD systems were investigated. In addition, the ultimate fate of the NH<sub>3</sub> was investigated and a literature search was performed on the health and environmental effects of NH<sub>3</sub> and NH<sub>3</sub> salts.

### Approach

The analyses given in this report are based on the application of a SCR system to coal-fired utility boilers. Both low sulfur Western and high sulfur Eastern coals are considered. Table 1 gives the typical coal analyses and flue gas flows and compositions used in this study. These data represent the flue gas entering the SCR with the flue gas

treatment processing configuration specified in Figure 1. Table 2 gives the makeup water analysis used for the FGD system investigations.

The first step in this study was to conduct a literature search to obtain information concerning the problems and benefits which could result from the presence of NH<sub>3</sub> in gases entering ESP and FGD systems, and to gather data concerning health effects of NH<sub>3</sub> and NH<sub>3</sub> salts. Information was also collected concerning the formation of NH<sub>3</sub> salts by the reaction of NH<sub>3</sub> with gaseous acidic species in the flue gas. Baghouse and ESP data were sought to determine the ability of these control devices to remove NH<sub>3</sub> particulates.

Since NH<sub>3</sub> has been used to improve ESP performance, the literature available was used to determine the ultimate fate of the NH<sub>3</sub> in ESP systems. This information was also used to identify potential operating problems and alternatives for avoiding the problems which may result from NH<sub>3</sub> upstream of the ESP. Unlike ESP's, little information is available on the effect of NH<sub>3</sub> compounds on baghouses. NH<sub>3</sub> particulate removals were therefore based on the ability of baghouses to remove fine particulates.

The investigation of the effect of NH<sub>3</sub> on FGD system operation was performed by using the Radian Inorganic Process Simulation (RIPS) computer model. This model consists of a group of subroutines which can be used to simulate the unit processes and chemical phenomena in lime/limestone FGD systems. The computer model considers 10 dissolved species: calcium, magnesium, sodium, ammonia, phosphate, chloride, carbonate, nitrate, sulfite, and sulfate. The model calculates the equilibrium partial pressure of CO<sub>2</sub>, SO<sub>2</sub>, and NH<sub>3</sub> gases for a given aqueous solution composition. A more detailed discussion of the computer model is presented in the appendix of the full report.

The computer model was used to determine NH<sub>3</sub> removal efficiencies in limestone scrubbing systems applied to utility boilers firing the Eastern and Western coals characterized in Table 1. Simulations, performed for various concentrations of NH<sub>3</sub> entering the FGD system (0-100 ppm), were used to determine:

1. Expected NH<sub>3</sub> removal efficiency.
2. Required liquid-to-gas ratio (L/G) to achieve 90 percent SO<sub>2</sub> removal.

**Table 1. Coal Analyses and Flue Gas Parameters For Representative Eastern and Western Coals**

	Eastern	Western
Coal compositions (wt %)		
Carbon	57.7	47.85
Hydrogen	3.7	3.40
Nitrogen	0.9	0.62
Chlorine	0.1	0.03
Sulfur	4.0	0.48
Ash	16.0	6.40
Oxygen	5.8	10.83
Moisture	12.0	30.40
HHV cal/g (Btu/lb)	5,606 (10,000)	4,451 (8,020)
Flue gas parameters <sup>a</sup>		
SO <sub>2</sub> (mole %)	0.2929	0.0398
SO <sub>3</sub>	0.0030	0.0004
H <sub>2</sub> O	8.190	11.92
CO <sub>2</sub>	11.95	11.88
N <sub>2</sub>	73.73	70.50
O <sub>2</sub>	5.824	5.656
HCl	0.00704	0.0100-0.0000
NH <sub>3</sub>	0.0100-0.0000	0.0100-0.0000
Fly ash, g/m <sup>3</sup> (gr/ft <sup>3</sup> )	6.32 (2.77)	3.02 (1.32)
Flow, <sup>b</sup> Nm <sup>3</sup> /sec (scfm)	553 (1.17 = 10 <sup>6</sup> )	607 (1.29 = 10 <sup>6</sup> )

<sup>a</sup>At exit from SCR system.

<sup>b</sup>Based on 500 MW net generating plant (550 MW gross generation)

Source: Ref. 4

**Table 2. Representative FGD System Makeup Water Analysis**

pH	7.3
Component (mg/l as ion)	
Carbonate	84.4
Sulfate	60.0
Calcium	35.0
Magnesium	8.2
Sodium	12.0
Chloride	15.0
Nitrate	0.8

Source: Ref. 4

3. Required reaction tank volume to prevent scale formation.

4. Sludge compositions.

Expected variations which might result for other FGD processes were also addressed. However, a more detailed analysis of the limestone FGD process was performed due to the large number of commercial limestone systems in operation in the U.S.

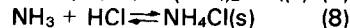
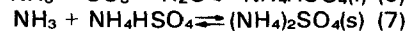
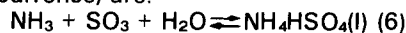
## Results

SCR systems in Japan have achieved 80-90 percent NO<sub>x</sub> reductions on gas- and oil-fired utility boilers. Commercial demonstrations of this technology on a coal-fired boiler are underway in Japan.<sup>(5)</sup> It is expected that 80-90

percent NO<sub>x</sub> reductions will result in 10-20 ppm of NH<sub>3</sub> in the gas exiting the SCR. The effect of this NH<sub>3</sub> on downstream equipment is summarized below.

### Ammonia Removal by Downstream Equipment

The results of a comparison study on the formation of NH<sub>3</sub> salts indicate that downstream of the air preheater, NH<sub>3</sub> will react with SO<sub>3</sub> and HCl to form particulate salts. The reactions, in order of occurrence, are:



A literature search concerning NH<sub>3</sub> injection for improved ESP performance indicated that, under normal operating conditions, the ESP would remove approximately 90 percent of these particulate salts. NH<sub>3</sub> removal by the ESP will only occur to the extent that the NH<sub>3</sub> will remain in the gas phase and pass through the ESP.

A baghouse is more efficient than an ESP in collecting fine particles; consequently, the predicted removal of NH<sub>3</sub> salts by a baghouse is 99 percent. As with the ESP, unreacted NH<sub>3</sub> will not be collected by a baghouse.

The level of NH<sub>3</sub> removal which will occur in FGD systems depends on the form of the NH<sub>3</sub> in the flue gas, the pH of

the FGD system scrubbing liquor, and the type of contactor used in the FGD.

Computer simulations were run at steady state NH<sub>3</sub> concentrations of the scrubber inlet of 0, 10, 20, 50, and 100 ppm at the inlet of a limestone scrubber for both Eastern and Western coal. The NH<sub>3</sub> removal in each case is shown in Table 3. For limestone scrubbing systems (with particulate removal upstream), about 50 percent of the gaseous NH<sub>3</sub> will be removed in a Western coal application (about 95 percent in an Eastern coal application) for NH<sub>3</sub> concentrations of 10-20 ppm entering the FGD system. At the lower NH<sub>3</sub> concentrations (1-3 ppm) normally expected at the FGD inlet, higher percentage removals are expected. Removals for Western coal are lower since the coal has a lower sulfur content. Low sulfur coals result in lower blowdown rates and high liquid NH<sub>3</sub> concentrations in the scrubbing liquor thereby reducing the concentration driving force for NH<sub>3</sub>(g) removal is proportional to the difference in the gas- and liquid-phase concentrations. Other FGD systems which typically operate at higher pH levels should not achieve gaseous NH<sub>3</sub> removals as high as limestone FGD systems.

The amount of NH<sub>3</sub> salts in the flue gas which will be removed in an FGD system will depend on the type of contactor used. A low pressure drop contactor such as a spray tower (commonly used in limestone FGD systems) should not remove a significant portion since these salts are typically submicron in size. Higher pressure drop contactors, such as packed or mobile bed types, may achieve greater removal of the submicron NH<sub>3</sub> salt particulate from the flue gas. However, for the typical configuration, most of the NH<sub>3</sub> salts would be removed in an upstream ESP or baghouse.

The NH<sub>3</sub> removal by a dry FGD system is now known. However, removal of NH<sub>3</sub> salts formed as the flue gas cools will be collected by the baghouse downstream of the FGD system.

To summarize, NH<sub>3</sub> exiting the SCR reactor can be partially removed by downstream equipment by two mechanisms: (1) reaction with SO<sub>3</sub> or HCl to form particulates which are partially removed by the ESP or baghouse, and (2) absorption of free NH<sub>3</sub> into the FGD scrubbing liquor. It is not possible to make a general prediction of the magnitude of NH<sub>3</sub> removal by these mechanisms since NH<sub>3</sub> removal is affected by the concentrations of

several flue gas components, especially SO<sub>2</sub>, SO<sub>3</sub> and HCl. Some hypothetical examples of NH<sub>3</sub> removal are illustrated below.

### Ultimate Fate of NH<sub>3</sub>

NH<sub>3</sub> by flue gas treating equipment is shown in Figures 2 through 4; three cases are considered:

1. Eastern coal, wet FGD.
2. Western coal, wet FGD.
3. Western coal, dry FGD.

In each case three levels of NH<sub>3</sub> emissions from the SCR system are shown. A normal emission level is considered to be 10 ppm; 50 ppm, a high level; and

100 ppm, significantly higher than anticipated. The material balances shown in the figures are calculated values based on a number of assumptions.

In the first case, Eastern coal with wet FGD, no NH<sub>3</sub> is emitted at the stack due to the large concentrations of SO<sub>3</sub> and HCl. The bulk of the NH<sub>3</sub> is removed as salts in the ESP or baghouse; small quantities are removed in the scrubber. This is not the case with Western coal (Figure 3) since SO<sub>3</sub> and HCl concentrations are substantially lower. With Western coal, the NH<sub>3</sub> reacts completely with SO<sub>3</sub> and to equilibrium with HCl.

Some, but not much, of the remaining free NH<sub>3</sub> is removed by the scrubber. Even with 50 ppm of NH<sub>3</sub> in the SCR exit gas, the stack concentration is only 15 ppm which is acceptably low. The stack gas also contains the equivalent of 12 ppm of NH<sub>4</sub>Cl as particulate. With Western coal and a spray dryer the amount of NH<sub>3</sub> in the stack gas will not change, but the amount of particulates will be significantly reduced by the downstream baghouse.

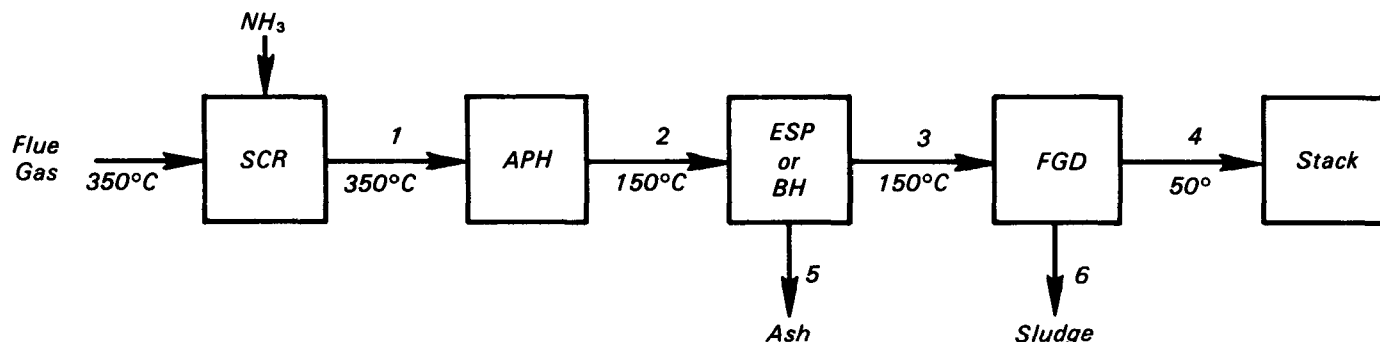
These material balances indicate that NH<sub>3</sub> emissions will not be a problem, even at SCR reactor outlet concentrations of up to 50 ppm, when the SCR system is followed by a particulate collection device and an FGD system. NH<sub>3</sub> emissions will be significantly reduced by this downstream equipment when high sulfur Eastern coal is used. The NH<sub>3</sub> that is removed by downstream equipment ultimately ends up in the waste streams from these processes, and it is these streams which have a potential for environmental impact.

### Impacts of NH<sub>3</sub> on Downstream Equipment

NH<sub>3</sub> in the flue gas can impact downstream equipment in two ways: by

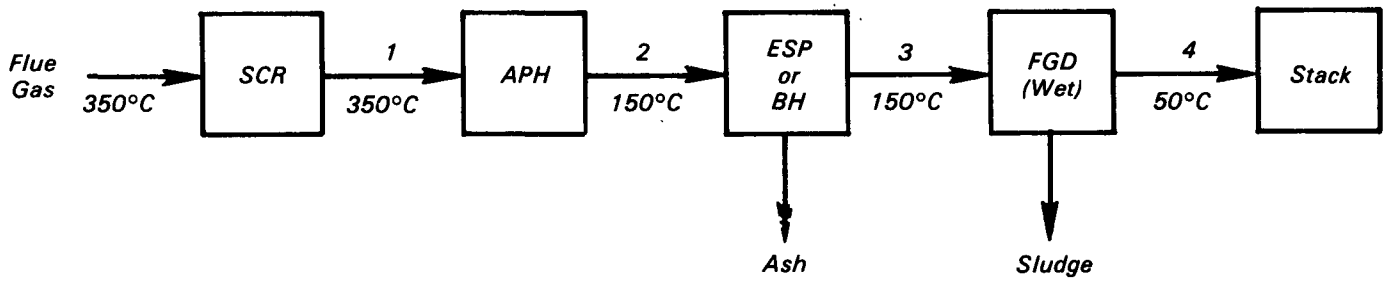
**Table 3.** Removal by FGD Scrubber as a Function of Coal Type and NH<sub>3</sub> Concentration

Case	NH <sub>3</sub> in Scrubber Inlet Gas, ppm	Eastern Coal		Western Coal	
		pH	NH <sub>3</sub> removal, %	pH	NH <sub>3</sub> removal, %
1	100	6.0	85	6.2	25
2	50	5.9	90	6.0	35
3	20	5.9	93	5.9	45
4	10	5.9	95	5.9	55
5	0	5.9	100	5.8	100



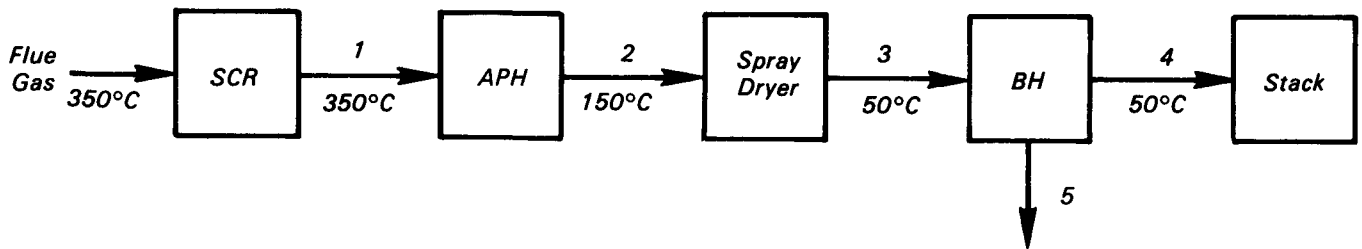
NH <sub>3</sub> in SCR Exit Gas	10 ppm						50 ppm						100 ppm					
	Stream	1	2	3	4	5	6	1	2	3	4	5	6	1	2	3	4	5
NH <sub>3</sub>	10	1	1	0	0	0	50	4	4	0	0	0	100	8	8	2	0	0
SO <sub>3</sub>	30	21	21	21	0	0	30	0	0	0	0	0	30	0	0	0	0	0
HCl	70	70	70	7	0	68	70	70	70	7	0	59	70	38	38	4	0	25
NH <sub>4</sub> HCO <sub>4</sub>	0	9	1	1	8	0	0	30	2	2	28	0	0	0	0	0	0	0
(NH <sub>4</sub> ) <sub>2</sub> SO <sub>4</sub>	0	0	0	0	0	0	0	7/5	1	1	6.5	0	0	30	2	2	28	0
NH <sub>4</sub> Cl	0	0	0	0.2	0	1	0	1	1	2	0	4	0	32	2	4	30	6

**Figure 2.** Fate of NH<sub>3</sub>, SO<sub>3</sub> and HCl in flue gas cleaning system—Eastern coal, wet FGD. (All concentrations in ppmv equivalents.)



NH <sub>3</sub> in SCR Exit Gas	10 ppm						50 ppm						100 ppm					
	1	2	3	4	5	6	1	2	3	4	5	6	1	2	3	4	5	6
Stream																		
NH <sub>3</sub>	10	2	2	2	0	0	50	28	28	15	0	0	100	71	71	64	0	0
SO <sub>3</sub>	4	0	0	0	0	0	4	0	0	0	0	0	4	0	0	0	0	0
HCl	25	25	25	3	0	20	25	11	11	1	0	8	25	4	4	0	0	1
NH <sub>4</sub> HSO <sub>4</sub>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(NH <sub>4</sub> ) <sub>2</sub> SO <sub>4</sub>	0	4	0.2	0.2	3.8	0	0	4	0.2	0.2	3.8	0	0	4	0.2	0.2	3.8	0
NH <sub>4</sub> Cl	0	0	0	0	0	2	0	14	1	12	13	2	0	21	1	5	20	3

Figure 3. Fate of NH<sub>3</sub>, SO<sub>3</sub>, and HCl in flue gas cleaning system—Western coal, wet FGD. (All concentrations in ppmv equivalent.)



NH <sub>3</sub> in SCR Exit Gas	10 ppm					50 ppm					100 ppm				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
Stream															
NH <sub>3</sub>	10	2	0	0	0	50	28	17	?	?	100	71	67	?	?
SO <sub>3</sub>	4	0	0	0	0	4	0	0	0	0	4	0	0	0	0
HCl	25	25	23	2	21	25	11	0	0	0	25	4	0	0	0
NH <sub>4</sub> HSO <sub>4</sub>	0	0		0	0	0	0	0	0	0	0	0	0	0	0
(NH <sub>4</sub> ) <sub>2</sub> SO <sub>4</sub>	0	4	4	0	4	0	4	4	0	4	0	4	4	0	4
NH <sub>4</sub> Cl	0	0	2	0	2	0	14	25	0	25	0	21	25	0	25

Figure 4. Fate of NH<sub>3</sub>, SO<sub>3</sub>, and HCl in flue gas cleaning system—Western coal, wet FGD. (All concentrations in ppmv equivalent.)

affecting the performance and/or the waste stream. These impacts were examined by both literature survey and original analysis.

NH<sub>3</sub> injection upstream of ESPs is a common practice at some plants and, in the older units, NH<sub>3</sub> levels (<50 ppm) have caused excessive fly ash adhesion. This operational problem may be overcome by increasing rapping frequency and/or intensity, or by periodic washing of the ESP collector plates. Baghouse operation may be impaired due to the presence of NH<sub>4</sub>HSO<sub>4</sub>, which is liquid at 147°C, and may cause blinding of the filter bags. More frequent cleaning and bag replacement may be required; however, investigations are needed to assess the severity of this problem since no commercial experience is available for study.

An alternate equipment configuration is the use of a hot-side ESP. Since the operating temperature upstream of the air preheater is about 100°C higher than the formation temperature of the NH<sub>3</sub> salts, very little NH<sub>3</sub> salt would be removed if the hot-side ESP were downstream of the SCR. Obviously, no NH<sub>3</sub> salt would be removed with the ESP upstream of the SCR. This configuration has been proposed for use in Japan to prevent contamination of the ash with the NH<sub>3</sub> salts. However, in this configuration, it is probable that control of the submicron NH<sub>3</sub> salts will be difficult. Low-pressure-drop SO<sub>2</sub> scrubbers will not remove these fine particulates, and it is possible that this configuration could result in a visible plume unless additional particulate control devices are employed.

A fabric filter following a spray dryer FGD system should remove most of the NH<sub>3</sub> salt particulates. Since NH<sub>4</sub>HSO<sub>4</sub> is not liquid at these temperatures (~65-95°C), the potential for filter media blinding is reduced.

With respect to FGD systems, the presence of NH<sub>3</sub> in the scrubbing liquor will be beneficial with respect to SO<sub>2</sub> removal. At expected FGD inlet NH<sub>3</sub> levels of 1-2 ppm, a slight rise in SO<sub>2</sub> removal efficiency may be observed. At higher levels (10-20 ppm inlet to FGD), the L/G ratio could be reduced while maintaining a constant 90 percent SO<sub>2</sub> removal. At very high levels (>50 ppm) of gaseous NH<sub>3</sub> entering the FGD system, SO<sub>2</sub> removal would improve substantially. However, NH<sub>3</sub> may also evolve over tanks, filters, and other open vessels causing some operator complaints.

Other types of wet FGD systems should exhibit slightly increased SO<sub>2</sub> removal because of NH<sub>3</sub> in the gas. Spray dryers will probably not remove significant amounts of gaseous NH<sub>3</sub>; however, the baghouse should collect essentially all of the NH<sub>3</sub> salts. Regenerable FGD systems may require additional equipment to remove NH<sub>3</sub> from the by-product stream.

Handling of the fly ash containing ammonium sulfate salts can potentially cause NH<sub>3</sub> emissions. The vapor pressure of NH<sub>3</sub> over the solid salts is very low; but, if the ash is wetted or sluiced, gaseous NH<sub>3</sub> will evolve. The phenomenon depends on the pH and NH<sub>3</sub> concentration of the liquid. Sluicing of the ash will dissolve the NH<sub>3</sub> salts and could lead to aqueous NH<sub>3</sub> discharges if the sludge water is not recycled.

In the SCR exit gas, 10 ppm of NH<sub>3</sub> could result in NH<sub>3</sub> concentrations in the ash pond overflow of 30 mg/l for Eastern coal and 60 mg/l for Western coal. The potential also exists for NH<sub>3</sub> to leach into the ground water from the fly ash pond. With proper pond lining, however, the probability of this leaching will be very low.

Aqueous NH<sub>3</sub> concentrations of 200-1300 mg/l are possible in FGD sludge liquors when SCR NH<sub>3</sub> emissions are 30 ppm, depending on the coal type. For this reason, leachate from FGD sludge ponds could cause contamination of groundwaters due to the NH<sub>3</sub>. However, the amount of NH<sub>3</sub> that would reach groundwaters from FGD and ash disposal ponds is unknown. Again, proper pond lining would eliminate these concerns. Depending on the pond pH and aqueous NH<sub>3</sub> concentration, gaseous NH<sub>3</sub> could evolve from the sludge ponds. In some cases, biological treatment or stripping of pond discharge water may be necessary.

Gaseous NH<sub>3</sub> or NH<sub>3</sub> salts could theoretically result in visible plume formation; however, most of the NH<sub>3</sub> salts will be removed in a cold-side ESP or baghouse, minimizing the chance of a plume. Systems using a hot-side ESP may have (NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>/NH<sub>4</sub>HSO<sub>4</sub> plume formation problems. A high-pressure-drop mist eliminator may be capable of preventing visible plume formation by removing the fine NH<sub>3</sub> particulates passing through the FGD system, but would increase the FGD system capital costs about 5 percent (based on limestone). Another potential source of visible plume formation is the reaction of gaseous NH<sub>3</sub> with SO<sub>2</sub>(g) leaving the

stack gas. This phenomenon is not expected to occur, except at high levels of excess NH<sub>3</sub> (>10 ppm) exiting the FGD system. These levels of NH<sub>3</sub> emissions can exist with Western coal-fired systems when the steady state SCR NH<sub>3</sub> emissions are >50 ppm. This level of SCR emissions is higher than the guaranteed levels and would only be expected during upset conditions (which are transient, short-term situations). With Eastern coal, stack gas NH<sub>3</sub> concentrations are expected always to be <<10 ppm. Japanese installations utilizing either SCR or NH<sub>3</sub> injection for ash conditioning have indicated that plume formation is not a problem.

### Health Effects

The health and environmental effects of a SCR will be minimal if standard operating and safety procedures are followed. Low levels of NH<sub>3</sub> are neither toxic nor carcinogenic. A major spill of NH<sub>3</sub>, however, could result in a locally toxic atmosphere for plant personnel.

### Conclusions

#### Ultimate Fate of Ammonia

- Much of the NH<sub>3</sub> will react with SO<sub>2</sub> and HCl to form salts which will be significantly reduced by downstream particulate removal equipment. 90-95 percent of the NH<sub>3</sub> should react to form these salts for exit SCR levels of 10-20 ppm NH<sub>3</sub>, and 10-20 ppm SO<sub>3</sub>.
- The removal of gaseous NH<sub>3</sub> by FGD systems will depend heavily on the scrubbing liquor pH. Removal efficiencies for limestone systems were calculated to be about 50 percent Western coal and about 94 percent for Eastern coal (assuming FGD inlet gaseous ammonia levels of 10-20 ppm). At the normally expected FGD inlet NH<sub>3</sub> concentrations of 1-3 ppm, higher removals would be realized. Other FGD systems which operate at higher pH levels than limestone systems should experience lower gaseous NH<sub>3</sub> removal efficiencies.
- The removal of (NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub> and NH<sub>4</sub>HSO<sub>4</sub> particulates in an FGD system will depend on the contactor type. Open contactors such as spray towers (used in many limestone systems) should not achieve high NH<sub>3</sub> particulate removals since they are typically submicron particles. Higher pressure drop contactors, such as packed or mobile beds, could potentially achieve higher removals.

## Equipment and Operational Impacts

- The NH<sub>3</sub> salts formed will most likely improve ESP performance.
- Under high transient NH<sub>3</sub> concentrations, gaseous NH<sub>3</sub> would pass through the ESP. Some older plants report difficulty in cleaning the collection plates under these conditions.
- The removal of the submicron NH<sub>3</sub> salts by a baghouse should be as efficient as for other small particulates (>99 percent). However, the presence of liquid NH<sub>4</sub>HSO<sub>4</sub> could cause blinding of the filter media and result in increased bag cleaning and replacement for baghouses immediately following the air preheater.
- NH<sub>3</sub> absorbed by the FGD will be beneficial with respect to SO<sub>2</sub> removal. At the expected NH<sub>3</sub> concentration of 1-3 ppm into the FGD unit, the SO<sub>2</sub> removal may be slightly increased. For higher NH<sub>3</sub> concentrations, the increased absorbing capacity of the liquid could allow a reduction in L/G while maintaining constant SO<sub>2</sub> removal.
- Regenerable FGD systems may require special equipment to separate the by-product from NH<sub>3</sub> compounds.

## Waste Stream Impacts

- Under normal operating conditions, NH<sub>3</sub> emissions at the stack will be negligible. These low NH<sub>3</sub> emissions should eliminate the potential for plume formation at the stack.
- Wet handling of the collected fly ash could generate aqueous and gaseous NH<sub>3</sub> emissions, depending on the slurry pH and process configuration.
- Under normally expected FGD inlet concentration of NH<sub>3</sub> (1-3 ppm) and upstream collection of particulates after the air preheater, no significant environmental emissions are expected. Continuous high levels of NH<sub>3</sub> (>50 ppm) in the SCR exit gas could result in high NH<sub>3</sub> concentrations in the sludge pond water.
- Pond discharges could result in significant aqueous NH<sub>3</sub> emissions. To avoid these emissions, the ash sluice system could be operated in a closed-loop mode with all ash pond overflow recycled to sluice ash. Another alternative is to reuse a portion or all of the ash pond overflow elsewhere in the plant, such as for FGD system makeup. Stripping and/or biological treatment

may be required for NH<sub>3</sub> removal from wastewater. Secondary gaseous emissions from the pond could also occur, depending on the liquid pH and process configuration.

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*The complete report, entitled "Impact of NO<sub>x</sub> Selective Catalytic Reduction Processes on Flue Gas Cleaning Systems," (Order No. PB 82-240 086; Cost: \$12.00, subject to change) will be available only from:*

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