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Division of Air
Resources Management

Orlando Utilities Commission
OUC C.H. Stanton Energy Center Unit 2

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September 17, 1991

Bureau of Air Regulation
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Responses to DER.

Attention: Mr. Clair H. Fancy, P.E.

Gentlemen:

This is in response to questions during our meeting in your offices on September 12, 1991.

Sulfur trioxide in the presence of ammonia will form ammonia sulfate and ammonia bisulfate salts. Ammonia bisulfate is a sticky substance which can deposit on downstream equipment. Ammonia bisulfate will tend to liquefy at a temperature of about 410F. This temperature will occur in the intermediate baskets of the air heaters. Once liquified it solidifies in nodules in the space between the intermediate and cold end baskets. The result can be increased pressure drop, and eventual plugging of the air heater. Off-line water washing are necessary to remove the soluble deposits. To help prevent plugging of the air heater due to ammonia sulfate formation, ammonia slip must be limited to approximately 3 to 5 ppm which requires more catalyst volume. Considering the relatively high sulfur concentrations of coals under consideration for C. H. Stanton Unit 2 it may be necessary to limit ammonia slip further. The frequency of air heater washings are directly related to NH_3 slip. Test data from EPDC Takehara Unit 1 indicates that the air heater needs to be washed approximately once every six months.[1] EPDC Takehara Unit 3 requires more frequent air heater washing due to the design of the air heater. Both SCR systems are designed to limit NH_3 slip to 5 ppm.

In addition to limiting NH_3, conversion of SO_2 to SO_3 must also be controlled. SO_2 conversion in an SCR is impacted by the following parameters.[2]

- Chemical composition of the catalyst - particularly vanadium pentoxide content.
- Ratio of surface area of catalyst material to volumetric gas flow.
- Flue gas temperature.

The reaction between NO_x and NH_3 takes place of the surface of the catalyst whereas, the conversion of SO_2 to SO_3 is a volumetric reaction.[3] Therefore, catalyst volume must be decreased while maintaining surface area in order to minimize SO_2 conversion and NH_3 slip. Catalyst designed without vanadium pentoxide will also reduce SO_2 conversion. However, this will also reduce the NO_x removal capability of the catalyst requiring an increase in catalyst volume.[4] The Zolling Power Plant in Germany recently replaced an existing SCR catalyst with a new SCR catalyst designed to minimize SO_2 conversion while burning a 0.96% sulfur fuel. The new catalyst has an SO_2 conversion rate of less than 1%.[5] The effects of SO_3 has been minimized at the Zolling Power Plant with the new catalyst design, however, it should also be noted that this unit is routinely shutdown every weekend allowing for periodic maintenance.

Approximately 1% of the SO_2 generated in the boiler is converted to SO_3. Therefore, regardless of the SO_2 conversion in the SCR catalyst, there will be SO_3 present in the flue gas to react with NH_3 leaving the SCR, resulting in ammonia bisulfate fouling.

The OUC C.H. Stanton Unit 2 will be burning a fuel with significantly higher sulfur content than what is typically burned at European power plants and will be operating on a continual basis. It is apparent that successful operation of SCR systems in Europe and Japan is attributable to years of previous operating experience.

The impacts of availability loss associated with SCR operation can occur in a number of ways. Maintenance and replacement of catalysts requires shutdown, cooldown, and re-start time, in addition to active work time. The same is true for off-line water washings of the air heater. Excursions in ammonia slip that contaminate fly ash may limit unit availability by creating problems with the disposal of unsalable flyash, and by complicating disposal of scrubber sludge. The sludge handling subcontractor currently operating the SEC Unit 1 sludge disposal system, has advised that they could not handle ammonia laden fly ash or sludge in the fixation process because of hazards to personnel. In circumstances of a worn catalyst where the unit cannot be removed form service, the requirements to limit ammonia slip may limit the capacity of the plant. Although the individual contributions of these factors is expected to be small, the combined effect on availability may be significant. Best estimates of contributions are as follows.

Source of Unavailability	Annual
Catalyst Maintenance and replacement	4 days
Offline water washing	6 days
Fly ash and scrubber sludge disposal problems	5 days
Derate to limit slip	3 days (equiv.)
SCR support systems	1 day
Total	19 days
Total Unavailability	5.4%

Although it may sometimes be possible to have activities coincide with planned outages, the fact that Stanton Unit 2 represents almost a quarter of OUC's on-line generation capacity means that its outage schedule is inflexible.

It should also be taken into consideration that in matters where no operating experience exists (there are no similar U.S. coal applications of this technology), the concept of availability cannot be divorced from the concept of risk. Whereas, the numbers stated above reflect "best estimate" figures, a significant probability exists that these numbers may have magnitudes to twice to three times that shown.

In light of the above we would like to renew our offer of settlement to voluntarily retrofit Unit 1 with new low NO_x burners, with the result of substantial overall emission reduction of NO_x under the bubble concept. We also request that you arrange a meeting with EPA in Atlanta to further discuss this offer with the regional administrator or his designated representative, in light of the fact that this decision affects millions of residents in the cities receiving power from Stanton Unit 2.

Very truly yours,

BLACK & VEATCH

J. R. Cochran

mef

cc: Barry Andrews
Preston Lewis
Buck Oven
Richard Donalyn/Office of General Council
Greg Worley/EPA Region 4
Brian Beals/ EPA Region 4
Thomas B. Tart/OUC
file
M. Linn
C. Collins
G. Harper, EPA

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2. R. Jaerschky, "SO_3 Generation - Jeopardizing Catalyst Operation", Isar-Amperwerke AG, Presented at the 1991 Joint Symposium on Stationary Combustion NO_x Control-EPA/EPRI

3. R. Jaerschky

4. R. Jaerschky

5. R. Jaerschky

SO_3 GENERATION - JEOPARDIZING CATALYST OPERATION?

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SO_3 GENERATION - JEOPARDIZING CATALYST OPERATION?

ABSTRACT

Isar-Amperwerke AG's modern, hard-coal-fired combined power and district heating plant in Zolling went into operation at the end of 1985. To ensure conformance with the applicable emission limits, the power plant was initially equipped with primary NO_x reduction measures, a high-efficiency electrostatic precipitator and a desulfurization plant. With the introduction of a more stringent limit for NO_x emissions, it became necessary to retrofit a $DeNO_x$ plant. This $DeNO_x$ plant, which functions on the principle of selective catalytic reduction using ammonia, went into operation at the beginning of 1988 and achieved the required separation efficiency without difficulty.

After a brief period of operation, however, acidic particles started to be emitted. Extensive investigations revealed that these emissions were the result of the catalysts' having a very high SO_2/SO_3 conversion rate.

On the basis of the investigations results, steps were taken which reduced the emission of acidic particles to an absolute minimum. It became apparent, though, that a permanent solution to the problem would require replacing the catalysts.

For this reason, the catalysts were replaced mid-1990 after approximately 12,000 hours of operation by a new type with a much lower conversion rate.

This paper reports on the operating results obtained with the old catalysts, the investigations carried out regarding SO_2/SO_3 conversion, and first experiences gained with the new fill.

SO_3 GENERATION-
JEOPARDIZING CATALYST OPERATION?

ZOLLING POWER PLANT

Zolling Power Plant - formerly known as Leiningerwerk Power Plant Unit 5 - benefits from a number of environmental protection features:

- High efficiency thanks to supercritical steam conditions
- Extraction of district heat
- Highly efficient flue gas cleaning with $DeNO_x$, dust removal and desulfurization
- A liquid waste processing system with ammonia stripper
- A pleasant architectural design (Fig. 1)

Figure 1. Zolling Power Plant

The technical data of the Zolling Power Plant are listed in Table 1:

Table 1

TECHNICAL DATA

Max. thermal output of furnace	1,144 MW
Main steam mass flow	384 kg/s
Main steam temperature	540 °C
Main steam pressure	274 bar
Reheat temperature	540 °C
Reheat pressure	55 bar
Gross output at terminals	450 MW
Net output at terminals	420 MW
Max. district heat extraction	270 MW
(at a gross output at terminals of:	392 MW)

The power plant burns a mixture of German hard coals with a low ash and sulfur content (see Table 2). It operates primarily in the lower intermediate load range and is frequently shut down at weekends and at night.

Table 2

COAL ANALYSIS (AVERAGE VALUES)

Water	8.51 %
Ash (free of water)	7.52 %
Volatile substances (free of water and ash)	28.44 %
C content	73.46 %
H content	4.32 %
N content	1.54 %
S content	0.96 %
Net calorific value	28.99 MJ/kg

FLUE GAS CLEANING FACILITIES

Table 3 correlates the applicalbe emission limits in Germany with the flue gas values at the boiler outlet and at the stack of Zolling Power Plant:

Table 3

	Dimension	Raw gas	Limit	Clean gas
NO_x	mg/m_N^3 (6% O_2)	650	200	190
SO_2	mg/m_N^3 (6% O_2)	1,900	400*)	200
Dust	mg/m_N^3 (6% O_2)	7,100	50	5

*) but at least 85% SO_2 separation

To ensure conformance with the applicable limits, the power plant is equipped with a high-dust $DeNO_x$ plant, an electrostatic precipitator and a flue gas desulfurization plant (FGD), the arrangement of which is shown in Fig. 2.

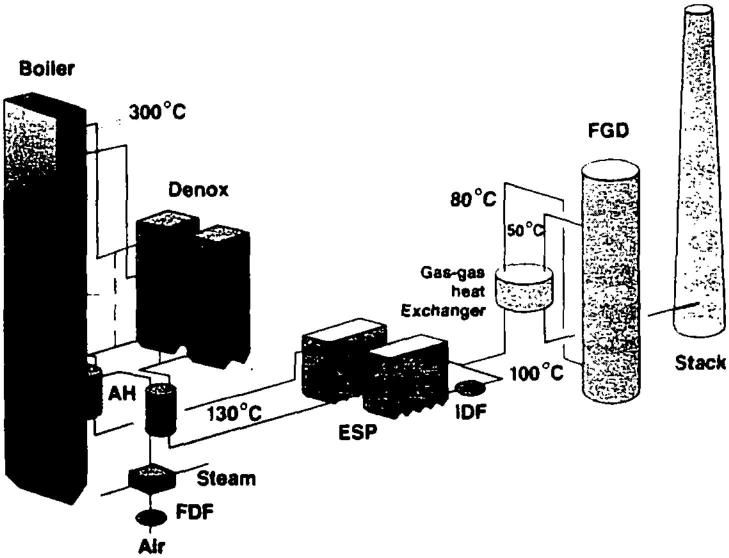

Figure 2. Flue Gas Flow Diagram

The following in-furnace NO_x controls are also incorporated into the boiler:

- Dynamic classifier for finer pulverization
- Low-NO_x burners for quasi-stoichiometric combustion
- Air staging with over fire air

These primary measures result in a flue gas NO_x content of about 650 mg NO_2/m_N^3 (6% O_2) at the boiler outlet, together with a low nonburned residue content of the fly-ash (less then 3%) [1, 2].

DENO$_x$ PLANT

Zolling power plant initially went into operation without a $DeNO_x$ plant, but a retrofit was rendered necessary by increasingly stringent NO_x limits.

With a view to linking the boiler outlet and the air preheaters, we selected the high-dust configuration (see Fig. 2), which is more favorable from the energy point of view.

We decided on plate-type catalytic converters on account of their superior corrosion resistance and lower pressure losses. The main design data of the $DeNO_x$ plant are summarized in Table 4.

Table 4

DESIGN DATA OF DENO$_x$ PLANT

Flue gas volumetric flow (damp)	400	m_N^3/s
Flue gas temperature min./max.	300 °C/ 400	°C
NO_x reduction	70	%
Max. NH_3 slip after 12,000 hours of operation	5	ppm
Volume of catalytic material	522	m^3
Specific surface area of catalytic material	330	m^2/m^3

OPERATING RESULTS

The objective of 70% NO_x reduction was reached without difficulty throughout the service life of the catalysts (approximately 12,000 hours). Activity checks carried out on the catalysts showed that deactivation took place much more slowly than had been postulated in their design (Fig. 3). After 12,000 hours of operation, the remaining activity of the catalysts was still 94% of the original value. This minimal drop in catalyst activity resulted in only a small increase in the ammonia content of the fly-ash from about 4 mg NH_3/kg at the start to around 10 mg/kg prior to the catalyst replacement. Figure 4 shows the increase in ammonia content of the fly-ash in the first quarter of 1990; these values point to an NH_3 slip of approximately 0.5 ppm.

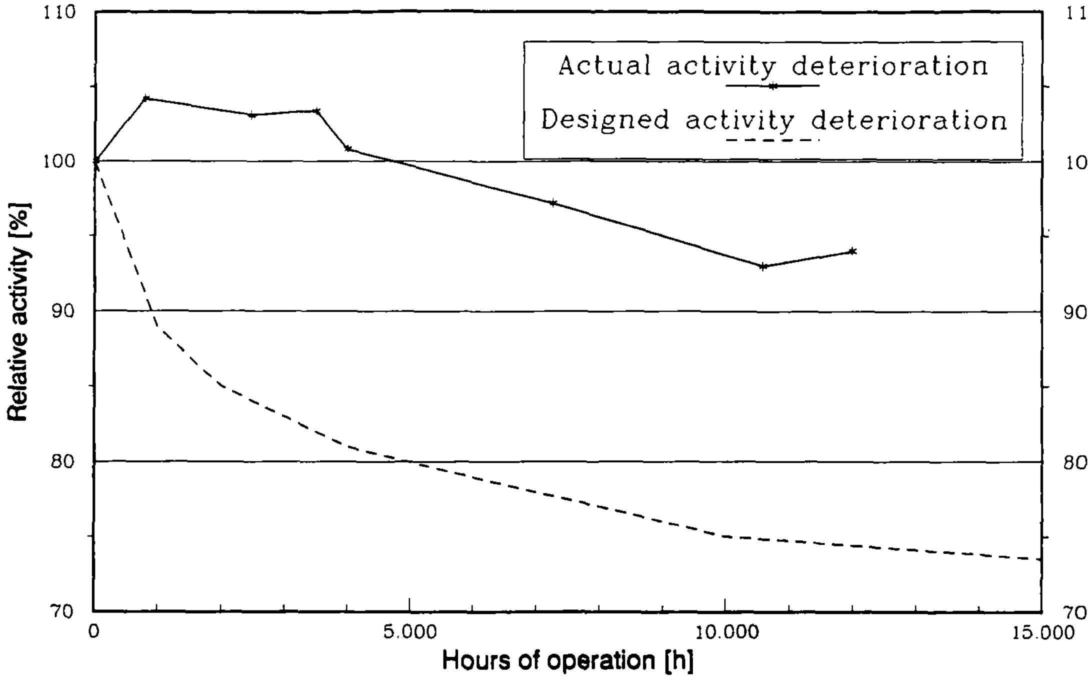

Figure 3. Activity Deterioration of Catalyst at Zolling Power Plant

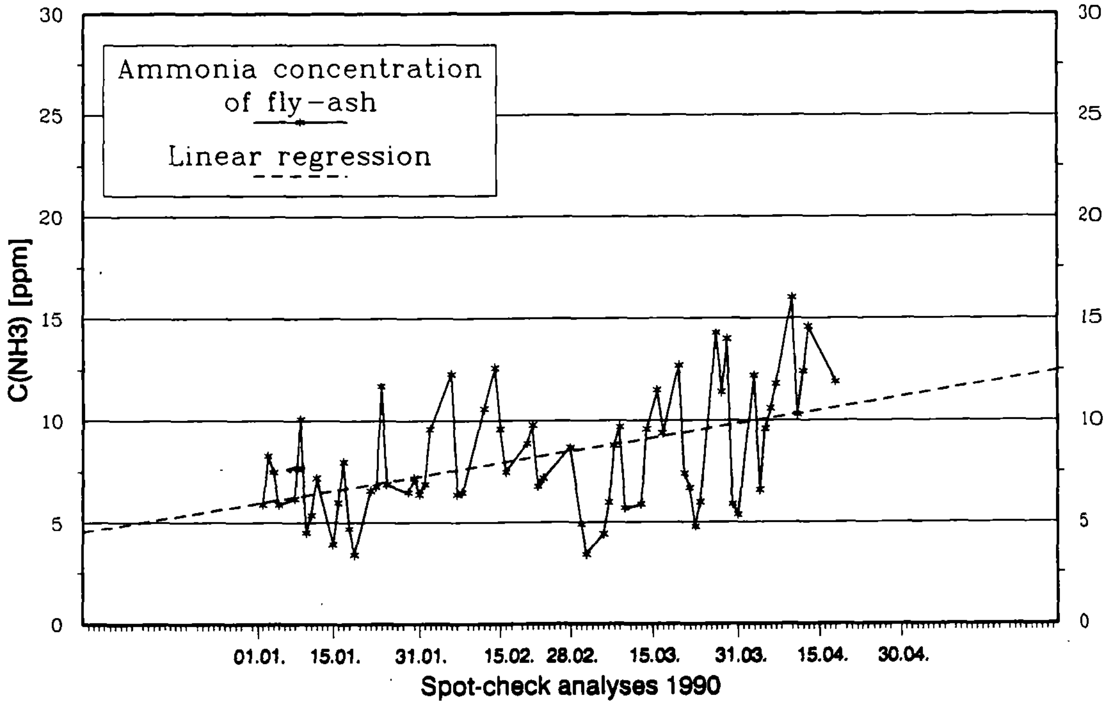

Figure 4. Ammonia Concentration in Fly-Ash Prior to Catalyst Replacement

Throghout the entire duration of operation, no problems were encountered with fly-ash deposits on the catalytic material; at the full-load duty point the pressure loss across all the catalyst layers ($h_{total} = 2m$) remained virtually constant at 3 mbar for the entire 12,000 hours of operation.

After only a short period of operation all these positive aspects were, however, overshadowed by the emission of acidic particles, which caused damage to the paintwork of cars parked in the vicinity of the power plant and jeopardized the good reputation of our power plant.

SO_3 GENERATION

After extensive investigations and measurements it became apparent that the emission of acidic particles was the result of oxidation of SO_2 to SO_3 in the $DeNO_x$ catalytic converters. This sulfur trioxid subsequently reacts with the steam, of which there is plenty in the flue gas, to form gaseous sulfuric acid.

The SO_2 conversion rate K (SO_2) is applied to quantify the oxidation of SO_2 to SO_3

$$K\ (SO_2) = \frac{C\ (SO_3)_{\text{downstream catalyst}} - C\ (SO_3)_{\text{upstream catalyst}}}{C\ (SO_2)_{\text{upstream catalyst}}} \times 100\%$$

with the C (SO_2) and C (SO_3) concentrations entered in ppm.

The following parameters have a significant effect on the conversion rate (cf. [3]):

- The chemical composition of the catalytic substance - particularly the vanadium pentoxide content
- The ratio of the surface area of the catalytic material to the flue gas volumetric flow
- The flue gas conditions, particularly the temperature

Figure 5 shows, as a function of the flue gas temperature, the SO_3 concentration C (SO_3) measured upstream and downstream of the catalytic converters in the course of the investigations.

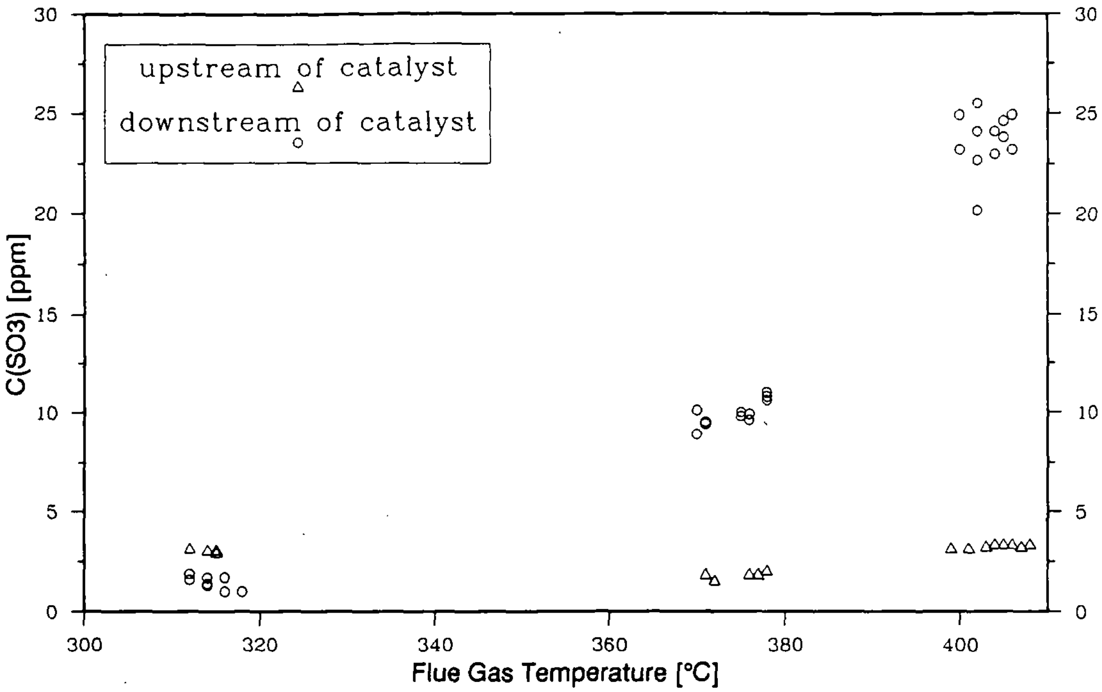

Figure 5. SO_3 Concentration in the Flue Gas

It became apparent that the SO_3 concentration in the flue gas was raised considerably by the $DeNO_x$ catalytic converters, and that there was a noticeable dependence on the flue gas temperature. At a flue gas SO_2 content of 665 ppm, the SO_2 conversion rate calculated for 375 °C was 1.2% and for 405 °C 3.3%. 707 F

761 F

At low load (120 MW) and temperatures of around 315 °C, the SO_3 content was lower downstream of the $DeNO_x$ plant than upstream, i.e. at this duty point the catalyst stores SO_3.

SO_3 CONCENTRATION IN FLUE GAS PATH

In order to better understand the mechanisms involved in the formation of acidic particles, several series of measurements were taken to determine the SO_3 concentrations at a given time at various points along the flue gas path downstream of the $DeNO_x$ plant. Figure 6 plots the SO_3 concentration downstream of the catalytic converter, downstream of the air preheater, and in the stack (i.e. downstream of the regenerative gas reheater); this series of measurements begins at low load (110 MW; flue gas temperature 315 °C), with a rapid increase to full load between 6.00 and 7.00 a.m., causing the temperature to rise to 375 °C.

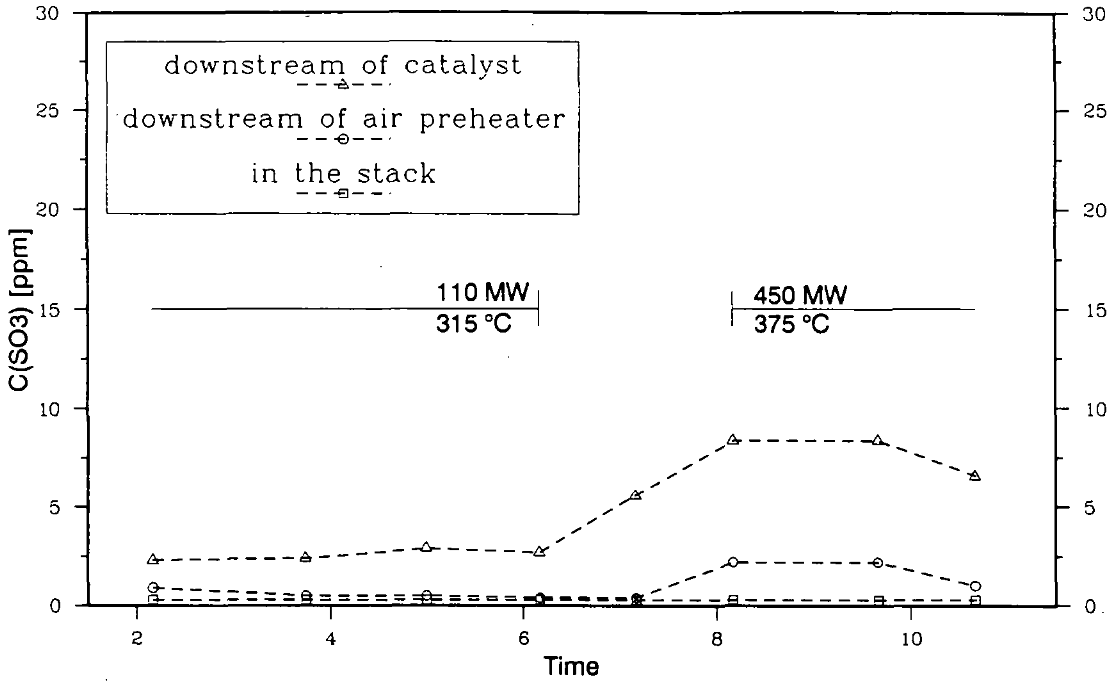

Figure 6. SO_3 Concentration in the Flue Gas as a Function of Time

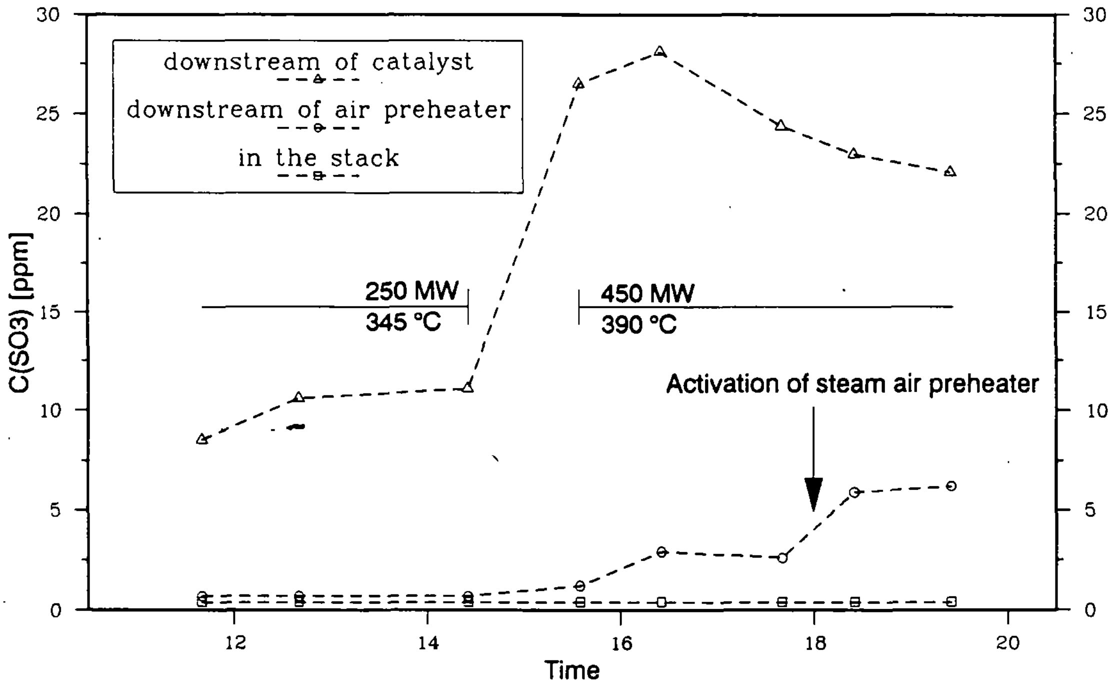

Figure 7. SO_3 Concentration in the Flue Gas as a Function of Time

A similar experiment is shown in Figure 7, but in this instance there was no soot blowing, which meant that the flue gas temperatures were higher. Starting from 250 MW and t_{FG} = 345 °C, the plant was run up to full load between 15.30 and 16.00, causing the flue gas temperature to rise to 390 °C. At 18.00 the flue gas temperature downstream of the air preheater was raised from 130 °C to 150 °C by activating the steam air preheaters.

In both cases the SO_3 concentration downsream of the $DeNO_x$ plant rose sharply on load increase and stabilized after about 3 to 4 hours at a somewhat lower level; this phenomenon is the result of thermal desorption of stored SO_3 (see Fig. 5).

The SO_3 concentrations downstream of the air preheater were considerably lower, which can be accounted for by the fact that the temperatures in the region of the air preheater are below the acid dew point. This results in sulfuric acid precipitating on the fly-ash, of which there are large quantities (sulfur content of the fly-ash 0.5%).

The amount of sulfuric acid which precipitates depends to a large degree on the temperature in the air preheater, as is clearly illustrated in Figure 7. Activating the steam air preheaters, thus causing the flue gas temperature downstream of the air preheaters to rise from 130 266F °C to 150 °C, resulted in a decrease in the precipitation of SO_3 from 24 ppm at 130 °C to 15 ppm at 150 °C.

302F

The measurements also revealed that almost all of the SO_3 still present in the flue gas downstream of the air preheater precipitates in the regenerative gas reheater; in all experiments the concentration of gaseous SO_3 in the stack was close to the minimum detectable level (approximately 0.5 ppm). As there is virtually no fly-ash in the region of regenerative gas reheater to absorb the precipitated acid fraction, further investigations were carried out to determine what was happening to the sulfuric acid.

After one week's operation, a plate was removed from the regenerative gas reheater. On the cold side of the heat exchanger plate there was an oily deposit of concentrated sulfuric acid which, extrapolated for the entire heat transfer surface of the regenerative gas reheater, amounted to a stored volume of 600 kg of sulfuric acid [3].

Solids such as residual dust, iron oxides and gypsum are deposited in this acid film. The rotation of the heat transfer plates allows these acid-soaked particles to pass to the treated gas side of the regenerative gas reheater, where they can break away and, given a sufficient gas velocity, be carried out of the stack.

Acidic particles were emitted primarily on rapid load increase, particularly on plant run-up after weekend shutdown.

MEASURES TO PREVENT ACIDIC EMISSIONS

On the basis ot the investigations, the following steps were taken to prevent the emission of acidic particles:

- Soot blowing was stepped up to ensure that the flue gas temperature at boiler outlet remains below 380 °C, even at full load. As Figure 5 shows, this halves the SO_3 concentration downstream of the air preheaters, i.e. it reduces the SO_2 conversion rate from 3.3 % at 400 °C to 1.2%. As Figures 6 and 7 show, most of this SO_3 fraction can be seperated out in the air preheater.

- The flue gas temperature downstream of the air preheater was lowered, but at temperatures of less than 130 °C the pressure losses began to increase considerably, which was apparently the result of ammonia bisulfate deposits. The temperature was therefore raised again to 135 °C.

- Baffles were fitted to the floor of the flue gas ducts upstream and downstream of the regenerative air reheater for separation of the large particles (see Figure 8).

Figure 8. Baffles for Separation of Large Particles

- During each weekend shutdown the flue gas ducts in the region of the regenerative gas reheater were freed of particles.

- The blowing procedure of the regenerative gas reheater was modified; the hot and cold untreated gas sides are blown simultaneously so that the loosened particles remain on the untreated gas side.

- The plastic heat exchanger plates were removed from the regenerative gas reheater in order to reduce cooling and reheating and to achieve a smaller separator surface.

- The facility for drying the treated gas from the FGD plant using hot, SO_3-laden untreated gas was taken out of service.

- During each weekend shutdown the regenerative gas reheater was flushed out with large quantities of low-pressure water (10 bar). After each flushing cycle (duration 3 hours, volume of water around 150 m^3), the pH of the water discharged was measured; the flushing process was terminated as soon as a virtually neutral pH (around 6) was reached.

As a result of applying these measures, no emmisions of acidic particles have been detected since April 1989. However, the effort involved and the damage done to the plant components by the sulfuric acid (corrosion, shortening of service life, etc.) are tremendous. It was therefore decided that, in the long term, the catalyst would have to be replaced by a type with a lower conversion rate.

THE NEW CATALYST

Our Japanese suppliers, like all well-known manufacturers of catalytic converters, invested a lot of effort in developing a low-conversion catalyst.

Since the reduction of NO by NH_3 takes place on the surface of the catalyst, while the oxidation of SO_2 to SO_3 is a volumetric reaction, i.e. it increases linearly with the volume of the catalytic material, the plate thickness of the catalytic converters was reduced, thus decreasing the volume while maintaining the surface area for the $DeNO_x$ process.

A further significant reduction in the conversion rate was achieved by refraining from adding vanadium pentoxide to the catalytic material. However, this heavy metal promotes $DeNO_x$ activity, particularly in the 572-697 300 - 370 °C temperature range, this measure resulted in a 10% increase in the necessary catalyst volume to 574 m^3.

We were assured that this new catalyst would, at the same NO_x reduction efficiency of 70%, have a maximum ammonia slip of 5 ppm after 16,000 hours of operation. An SO_2 conversion rate of 0.9% at 400 °C was anticipated; inservice measurements under normal power plant conditions yielded values of around 0.7%. Right from the start, however, a noticeably higher NH_3 slip of about 1.5 ppm was registered.

FIRST OPERATING RESULTS WITH THE NEW CATALYST

The catalyst was replaced during the unit outage in June/July 1990. Acceptance testing was performed in September 1990 with the following results:

The catalyst achieves the required NO_x reduction without the increased NH_3 slip anticipated on the basis of the experimental measurements. Spot measurements showed the maximum to be 0.5 ppm NH_3 and the average 0.3 ppm. These values were confirmed by the fact that the NH_3 content of the fly-ash after catalyst replacement (Figure 9) is similar to that prior to replacement (Figure 4).

Figure 10 presents the results of the SO_3 measurements upstream and downstream of the catalytic converter.

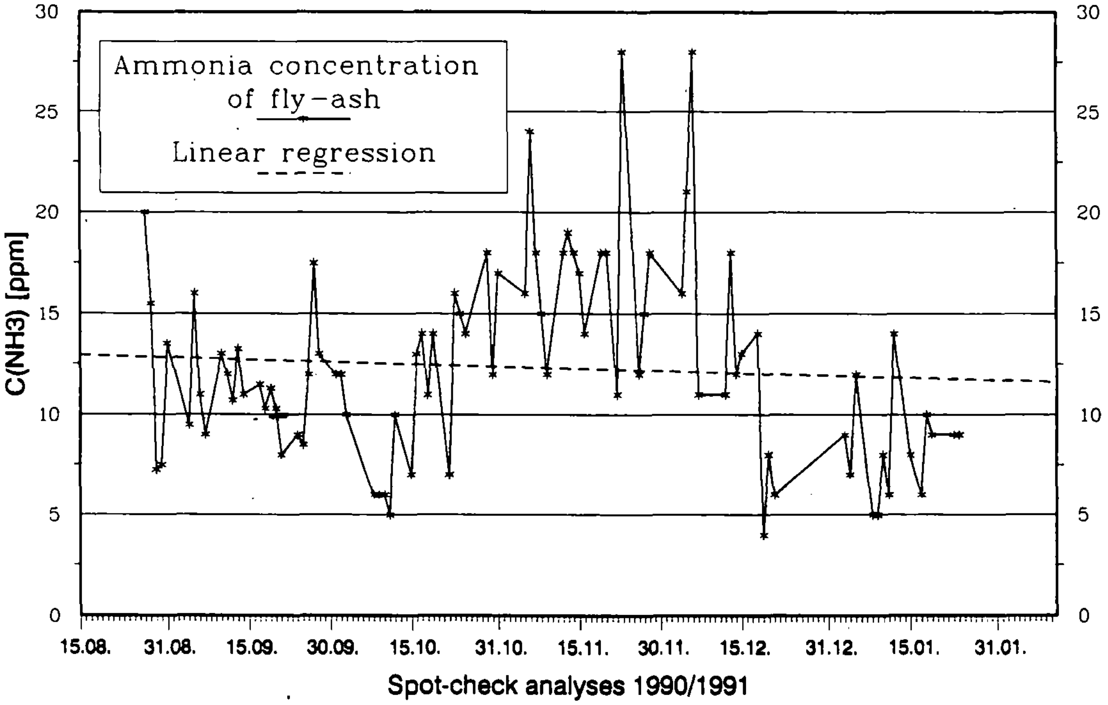

Figure 9. NH_3 Concentration in the Fly-Ash after Catalyst Replacement

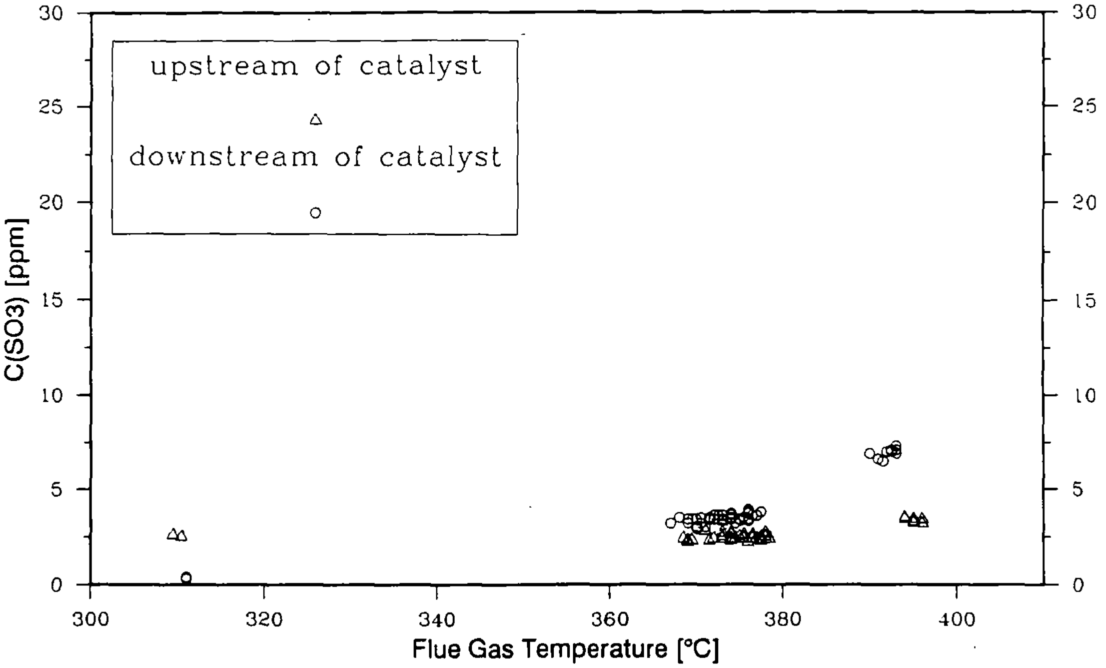

Figure 10. SO_3 Concentration in the Flue Gas

At a constant SO_3 content upstream of the catalytic converter, the values downstream of the $DeNO_x$ plant are considerably lower than those shown in Figure 5. At 394 °C, only 7 ppm were measured (old catalyst >15 ppm), thus confirming the SO_2 conversion rate of 0.7% at 400 °C in actual power plant operation.

As was the case with the old catalyst, storage of SO_3 occured in the low load range (t_{FG} = 315 °C). Figure 11 reveals the surprising fact that no detectable release of the stored SO_3 was observed on load increase from 200 to 450 MW.

Figure 11 also shows that the SO_3 concentration downstream of the air preheater is close to the minimum detectable level of about 0.3 ppm. It should be added that, under all load conditions, the gaseous SO_3 and sulfuric acid aerosols detected in the flue gas ducts downstream of the air preheater were always in the minimum detectable range.

As anticipated, the total SO_3 fraction can therefore be separated out in the air preheater by reducing the temperatures to values below the acid dew point. The fly-ash analyses confirm that the SO_3 content of the flue gas upstream of the air preheater is now considerably lower; at otherwise constant values, the sulfur content dropped from 0.5% to 0.3%.

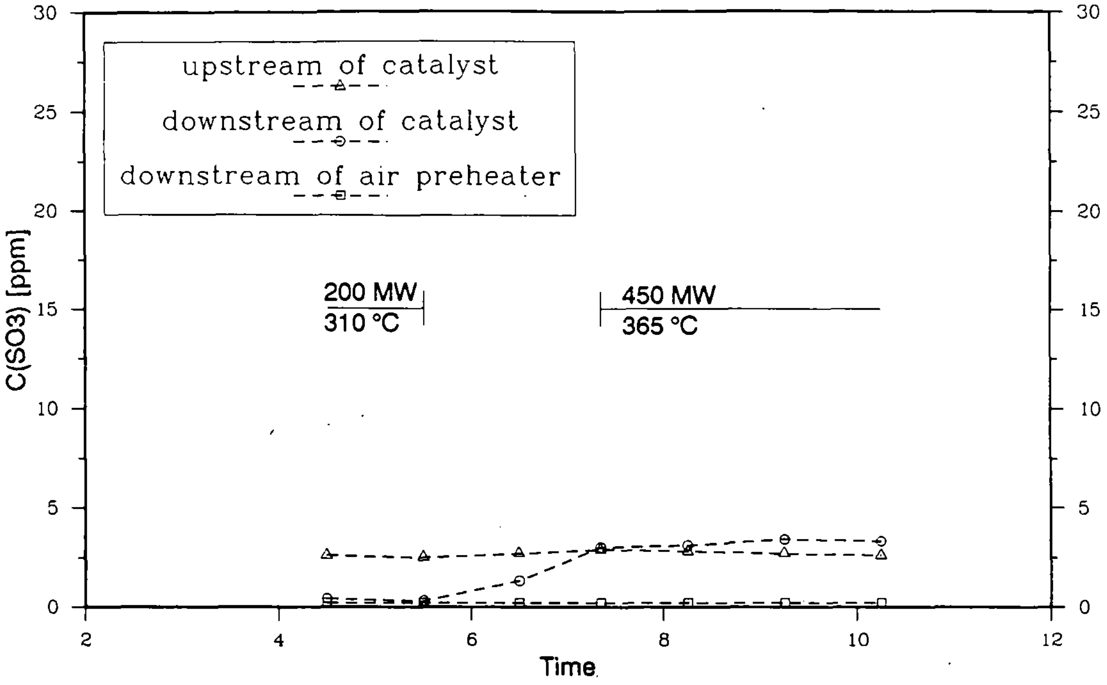

Figure 11. SO_3 Concentration in the Flue Gas Path as a Function of Time

Since catalyst replacement, there has apparently been no further precipitation of sulfuric acid in the regenerative gas reheater. On flushing the regenerative gas reheater with LP water, the first water discharged was found to be approximately neutral (pH > 4.5), so it was decided to extend the flushing intervals.

To summarize, the SO_2 conversion rate is one of the most significant criteria to be considered when selecting a high-dust catalytic converter.

Our experience with a low-conversion catalyst has shown that a trouble-free operation of the $DeNO_x$ plant is possible, without risk of the emission of acidic particles.

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1989 Joint Symposium On Stationary NOx Control

SEE CORRECTED Paper

OPERATING EXPERIENCE OF SCR SYSTEMS AT EPDC'S COAL FIRED POWER STATIONS

by: Tatsushi Mori and Noriyuki Shimizu
Thermal Power Department
Electric Power Development Co., Ltd.
Tokyo, Japan 104

ABSTRACT

Selective catalytic NOx reduction (SCR) system has been installed at Takehara coal fired No. 1 Unit (250 MW) and No. 3 Unit (700 MW) since July 1981 and March 1983 respectively, and is being installed at Matsuura coal fired No. 1 Unit (1,000 MW) which will be commissioned in July 1990. The SCR systems at Takehara No. 1 and No. 3 Units have been operated in good condition through catalyst addition and/or replacement. This paper refers to the current operating experience and inspection results of the SCR systems at Takehara No. 1 and No. 3 Units. The procedure of catalyst addition and replacement is also described. In addition outline of Matsuura No. 1 SCR system is introduced. Furthermore, SCR cost analysis is reviewed based on the latest information. In the final section, EPDC's R&D activity on SCR catalyst is presented.

1. INTRODUCTION

Regulations currently in force on power stations in Japan as to air pollutant emissions include national laws (Air Pollution Control Law), prefectural ordinances and individual agreements made with concerned municipalities (agreements on environmental preservation). Among these three kinds of regulations, prefectural regulations are generally stricter than the national laws, and regulations specified in agreements with concerned municipalities are stricter than prefectural regulations. This means that emission levels are practically regulated by agreements with concerned municipalities. Historically speaking, in addition, the laws have been revised several times for stricter regulations, and regulations agreed in agreements have tended to be stricter one after the other although local characteristics affect such agreements much.

As for NOx emission, one of the air pollutants emitted from power stations, combustion methods were improved at initial stages by using the two stage combustion method, low NOx burners and their improved versions. It was generally recognized, however, that such methods as suppression of NOx generation would be inadequate when emission standards got stricter than the 100 to 200 ppm level. Technical development of flue gas denitrification processes then started. Currently, SCR process, which is one of the dry flue gas denitrification processes, is used widely at thermal power stations in Japan mainly because of its advantages that the system is simple and that it produces no byproducts. As of March 1988, the SCR system is used at thermal power stations of which generation capacity amounts to 36.4 GW, corresponding to 37% of the total thermal power generation capacity of 99.7 GW in Japan. As for coal fired power stations among them, the SCR process is employed at 22 units, which corresponds to 46% of all coal fired units of 48. Counting by the power generation capacity, the SCR process is used for facilities of 6.2 GW, which corresponds to 54% of the total coal fired power generation capacity of 11.4 GW.

The SCR system is classifiable into a high dust and a low dust systems as seen in Figure 1. This distinction comes from the location of the SCR, which is upstream or downstream of ESP in the flue gas flow. The ESP therefore is a cold side ESP for the high dust SCR system, and a hot side ESP for the low dust SCR system. Either process has its own merits and demerits, but both of them have been employed actually for coal fired power generation, and they are operating well. EPDC employs the low dust system for pulverized coal firing power plants. Note that the systems shown in Figure 1 include a flue gas desulfurization system which is in general use in Japan.

Ash of imported coals of low sulfur content used in Japan shows high electric resistances of more than 10^{12} ohm·cm at temperatures around 150°C corresponding to the temperature range of the cold side ESP. The dust collection efficiency of the ESP is deteriorated in such cases, and a larger dust collection area, i.e., a larger ESP is required to compensate for the low efficiency. The electric resistance of such ash, however, lowers to 10^{10} ohm·cm or lower around 350°C, which corresponds to the temperature range of the hot side ESP, and a favorable dust collection efficiency is assured. This means that the use of a hot side ESP, i.e., the use of the low dust SCR system, allows to use a wider variety of imported coals, and it provides a higher flexibility in procurement of overseas coals.

EPDC employed the low dust system in the SCR demonstration test from the reason given above and considering the results of the pilot plant tests which EPDC carried out in order to study SCR systems and catalysts at its power plants from 1976 to 1982 in cooperation with five representative SCR manufacturers.

Fully funded by the Government, EPDC carried out an SCR demonstration test at its Takehara No. 1 Unit (250 MW, PCF) for a year from July 1981. The demonstration plant was the first SCR system which treated all flue gas of a coal fired power unit. The system consisted of two trains of SCR, and catalysts supplied by two SCR manufacturers were used as selected in the preceding pilot plant test. The demonstration test ended with fruitful results. The SCR system of Takehara No. 1 Unit is operating in good condition since then as a commercial system with addition and replacement of catalyst. Results of the demonstration test and findings obtained through operational experiences thereafter were applied effectively to construction of Takehara No. 3 Unit (700 MW, PCF; full flue gas treatment by SCR). The SCR system of Takehara No. 3 Unit is operating well since its start of operation in March 1983 with one addition of catalyst since then. Those experiences are further reflected on Matsuura No. 1 Unit (1,000 MW, PCF; full flue gas treatment by SCR) which is currently under construction. The SCR system of the unit to be completed in July 1990 will be the largest in the world as an SCR system for coal fired power plant.

2. EXPERIENCES IN SCR OPERATION AT TAKEHARA NO. 1 AND NO. 3

2.1 Outline of SCR

Figure 2 shows a view of the SCR system of Takehara No. 3 Unit. The SCR system of Takehara No. 1 Unit is similar in shape to that of Takehara No. 3 Unit of vertical downflow type.

Table 1 shows current SCR specifications of Takehara No. 1 and No. 3 Units. The SCR system of Takehara No. 1 Unit consists of two trains, "A" and "B". The catalyst for A train is of plate type, and that for B train is honeycomb type. The SCR system of No. 3 Unit also consists of two trains, but both of them use the same plate type catalyst as that for A train of the No. 1 Unit. Although NOx concentrations at SCR inlet and outlet are different between No. 1 and No. 3 Units, NOx removal efficiency is the same value of 80%.

2.2 SCR Operation

Figure 3 shows records obtained at start up operation of Takehara No. 3 Unit. After the start of the boiler, ammonia is not injected until the flue gas temperature exceeds 300°C. Below that temperature, denitrification reaction rate is very low, and ammonia, if injected, reacts with SO_3 in flue gas and produces ammonium sulfate compounds. Such ammonium sulfate compounds deposit on catalyst surfaces deteriorating the catalyst activity. When the flue gas temperature exceeds 300°C, denitrification reactions occur by injection of ammonia, and the NOx level lowers. Although the time is short, the level of NOx emission is high until service-in of the SCR system. To be able to start the SCR as soon as possible in the plant start up operation is very important. Takehara No. 3 Unit is equipped with a boiler economizer bypass system for this purpose. The damper opening position of this system is programmed as a function of the generator output, assuring to make the SCR inlet gas temperature high quickly for quick SCR service-in even at low generator output by introducing a part of the flue gas directly into the SCR bypassing the economizer.

Figure 4 shows the NOx control system of Takehara No. 3 Unit. Under normal operations, the amount of ammonia injection is controlled so that the NOx concentration at SCR outlet is 50 ppm. Figure 5 shows operation records obtained during a load change. Note that outlet NOx has been set lower in order to supress peak NOx concentrations during load change below the regulation value of 60 ppm. It is also possible to control the NOx removal efficiency by setting NH_3/NOx mole ratio.

EPDC carries out SCR performance tests before and/or after the periodical inspections which are conducted annually as specified by laws. Tables 2, 3 and 4 show SCR operational data obtained from the recent performance tests. The SCR systems have operated in stable condition as seen from the data.

2.3 SCR Performance Change in Time

The denitrification efficiency depends also on the NH_3/NOx mole ratio. If the catalyst activity deteriorates therefore, the denitrification efficiency lowers, unreacted ammonia increases even for ammonia injection of the same NH_3/NOx mole ratio. It is possible therefore to check the changes in catalyst activity by measuring unreacted ammonia concentration under the same flue gas conditions and the same denitrification efficiency. Figures 6, 7 and 8 show changes in unreacted ammonia concentration measured in the SCR performance tests carried out at the Takehara No. 1A, 1B and No. 3 SCRs. Figures indicate that the slip ammonia increases gradually due to the performance deterioration of SCR caused by gradual deactivation of catalyst in time and that the slip ammonia drops due to the improved performance of SCR by addition or replacement of catalyst.

Ammonium sulfate compounds which come from unreacted ammonia through SCR cause AH clogging and fan vibration. EPDC sets the maximum operating concentration of slip ammonia to be 5 ppm for Takehara No. 1 Unit and 4 ppm for Takehara No. 3 Unit from experiences in their operation. Figure 9 shows relations between the concentration of slip ammonia and the AH washing interval. Correlations between them are obvious, and AH washing frequency is roughly once per six months for each maximum operating concentration of slip ammonia. This means that one washing in a year between periodical inspections is adequate for AH maintenance. One thing to be noted on this matter is the shorter AH washing interval of the No. 3 Unit for the same concentration of slip ammonia compared with the No. 1 Unit. It may come from the remodeling of the AH of No. 3 Unit which was made after one year from the start of operation in order to burn high moisture content coal. The temperature distribution of AH elements along gas flow changed by the remodeling and the temperature range where ammonium sulfate compounds deposit moved toward upstream of gas flow, that is, to the intermediate portion of AH. The soot blower capacity was intensified to cope with this situation, but its effect seems still weak relatively.

The reason for using not the catalyst activity itself but the concentration of slip ammonia as the control value for SCR operation comes from the fact that the decrease in NOx removal efficiency, i.e., increase in NOx at SCR outlet, which comes from deterioration of catalyst activity in time can practically be taken care of by increasing the amount of ammonia injected. Therefore the concentration of slip ammonia is controlled on the SCR to prevent cloggings and vibrations of downstream facilities which are more serious for the plant operation.

EPDC periodically measures changes in the catalyst activity of actually installed sample catalyst as an aid for SCR performance management in addition to the control of slip ammonia described above. Figure 10 shows such an example of changes in activity of sample catalysts. The figure indicates that the deterioration of catalyst activity is rather slow after the initial period. Note that direct comparison among activity test results of sample catalysts for Takehara No. 1 A, No. 1 B and No. 3 SCRs is not appropriate due to different test conditions.

2.4 Catalyst Addition and Replacement

Catalyst additions and replacements have been made on Takehara No. 1A, 1B and Takehara No. 3 SCRs.

For Takehara No. 1A SCR, catalyst was added at the periodical inspections of 1983 and 1985, i.e., two years and four years after the start of operation of July 1981 respectively. The amount of catalyst added at each addition was 16.5% of the original volume. Such additions were made because it was estimated from the trend in the concentration of slip ammonia that the AH washing frequency of more than once a year would be required if the SCR performance were not improved at such occasions. As shown in Figure 10, the rate of deterioration in catalyst activity is slow, and EPDC decided not to replace old catalyst but to add new catalyst to effectively utilize the activity of existing catalyst, thus achieving a higher SCR economy.

Catalyst amounting 13% of the original volume was added also for Takehara No. 3 SCR in the similar procedure at the periodical inspection of 1987, i.e., five years after commissioning in March 1983, because the primary AH washing frequency had increased to once per three months. Figure 11 and Photograph 1 show mounting of additional catalyst.

By such additions of catalyst, the rate of slip ammonia decreased as shown in Figs. 6 and 8, and the AH washing frequencies have decreased to levels where AH washing is made only at every periodical inspection for the No. 1A and once at every periodical inspection and once between inspections for the No. 3 Unit.

For the No. 1B SCR, on the other hand, a catalyst addition amounting 30% was carried out one year after commissioning in July 1981. The SO_3 conversion rate of the catalyst was rather high resulting in a high frequency of AH washing, and the tube type catalyst was replaced completely with honeycomb type catalyst at the periodical inspection of 1985, i.e., four years after commissioning. As shown in Figure 7, the concentration of slip ammonia is extremely low since the replacement, and AH washing is made only at each inspection.

EPDC manages catalyst addition or replacement schedule based on the trend of slip ammonia concentration obtained by the SCR performance tests. And the result of performance tests on the sample catalyst is considered also for the management. Figure 12 shows schematic diagram of the SCR performance management.

2.5 Inspection of SCR

The SCRs of Takehara No. 1 and No. 3 Units have been subjected to inspections at each periodical inspection of the plants. At the SCR inspection, accumulation of dust on catalyst layers, support beams and baffle plates, wear, deformation and corrosion of catalyst, and condition of ammonia injection nozzles are checked visually. Photograph 2 and Figure 13 show a state of dust accumulation on catalyst layers observed during inspection of the No. 1 SCRs. It has been confirmed that the accumulation of dust of the level shown in the photographs and the figure does not affect the SCR operation. Such dust, however, is removed during inspection. No major problems have been found in recent inspections, and SCR systems are operating well continuously without requiring any repairs except those which are made during periodical inspections.

2.6 Facilities Downstream SCR

Flue gas from boilers contains a small amount of SO_3 generated during combustion. The concentration of such SO_3 is on the order of 1% or less of the SO_2 concentration although it depends on the boiler type. In addition, the catalyst of the SCR converts a part of SO_2 into SO_3. A part of ammonia injected in the SCR, on the other hand, passes the SCR unreacted with NOx. Such slip ammonia and SO_3 in the flue gas react and cause deposits of ammonium hydrogen sulfate and ash compounds on downstream facilities existing in low temperature ranges such as AH and fans. These deposits then cause troubles such as clogging or vibration. The use of low SO_3 conversion rate catalyst and suppression of slip ammonia therefore are important factors for suppression of adverse effects due to ammonium sulfate compounds on downstream facilities.

For low dust denitrification systems, catalyst with low SO_3 conversion rate of 0.5% or less is generally used and SCRs are operated with the maximum value of around 5 ppm for slip ammonia. These measures have been effective for reducing AH clogging at Takehara power station as well.

Table 5 shows differential pressure change before and after AH washing. The table indicates that washing of AH is effective for cleaning the clogged AH. As seen in the case of Takehara No. 3 Unit, however, the washing of a secondary AH requires more than 10 hours, about 1,000 m^3 of washing water and waste water treatment, resulting decreased plant availability and increased maintenance costs. The selection of AH element shapes which prevent deposit accumulation and the selection of soot blower type and its operation schedule become important considerations to be given in the design and operation of the AH. As shown in Table 6, these considerations have been taken into account for Takehara No. 1 and No. 3 Units.

As for the BUF, which is a boost up fan for FGD system, among fans existing in downstream of the SCR, those of Takehara No. 1A and 1B have been cleaned frequently in recent years to cope with actual and possible vibration. The cause of the increase in vibration is unbalanced deposits on the impeller of BUFs. The relation between the deposit and the slip ammonia is not clear now, and it would be a future study item. The BUFs of Takehara No. 3 Unit have different type impeller and no specific problems exist without dust deposits.

For other downstream facilities of SCR such as IDF, FGD, Gas/Gas heat exchanger and FGD wastewater treatment system, no problems specifically ascribable to SCR have occurred.

3. CONSTRUCTION OF LARGE-SCALE SCR

EPDC has employed the low dust SCR as the denitrification system for Matsuura No. 1 Unit which is under construction and scheduled to start its commercial operation in July 1990. The decision comes from the use of the hot side ESP for collecting fly ash effectively for a wide variety of overseas coals. It goes without saying that the decision was made based on the huge data obtained through operation of hot side ESPs at Matsushima No. 1 and No. 2 Units and Takehara No. 3 Unit covering a time span of more than 8 years, experiences in the operation of low dust SCRs at Takehara No. 1 and No. 3 Units and results of economical evaluation of the whole flue gas treatment system for Matsuura No. 1 Unit including ESP, SCR, FGD and AH as well.

An overview of Matsuura No. 1 SCR is given in Figure 14 and Table 7.

Points of considerations taken into account in the design of Matsuura No. 1 SCR from experiences in operation of Takehara No. 1 and No. 3 SCRs include the following:

- Selection of optimum space velocity
- Additional catalyst space allowing for catalyst volume of 25%
- Suppression of dust deposits

  Distance between catalyst layers, distance between beam and catalyst layer, shape of baffle plate and employment of guide plate

- Improvements in the control system

The SCR plant of Matsuura No. 1 Unit will be the world's largest one when completed.

4. SCR COST

It has been a general understanding in Europe and the U.S. that the SCR system is rather costly. EPDC, however, has demonstrated that the SCR is rather attractive in cost through experiences in construction and operation of SCR systems for Takehara No. 1 and No. 3 Units.

An example of economic evaluation for SCR is presented here. Table 8 shows premises employed for the economic evaluation. The unit is assumed to be of middle size for base load operation. The coal characteristics are those typical for coals used at imported coal fired power stations in Japan. The SCR is a low dust type according to experiences at EPDC, and NOx concentrations at SCR inlet and outlet, and space velocity are based on those of Matsuura No. 1 Unit. As for the catalyst life, this example assumes that the whole catalyst is replaced at a cycle of 4 years, which has a large margin on the safety side compared with the catalyst life experienced at Takehara No. 1A and Takehara No. 3 SCRs. As for the economic indices, the exchange rate of 130 yen/$ is used, and the discount rate of 10%, which is typical for Japanese electric utilities, is used. As for the facility life, it is assumed to be 20 years, which is more practical than the depreciation period of 7 years under taxation laws in Japan.

Table 9 shows the construction cost and the leverized bus-bar cost calculated from the premises described above. The construction cost and the bus-bar cost are as attractive as $66/kW and 3.6 mills/kWh respectively. As described in INTRODUCTION, SCR systems are widely used in Japan. Information which have been accumulated through actual construction and operation of SCR plants are dependable and uncertainty factors which may lead to a large contingency fund are minimal. In addition, the catalyst performance has been improved greatly. Further improvements in economy are expected for the future through competitions among manufacturers and technical innovations.

5. R&D ON SCR CATALYST

The catalyst life management is an important factor for stable operation of SCR plants. EPDC has been conducting various tests for evaluation of catalyst performance and clarification of factors for catalyst activity deterioration at its Engineering & Research Institute using a catalyst test equipment since 1985, and the catalyst life management is being carried out taking results of such tests into account in addition to the results of performance tests conducted at actual SCR plants.

The catalyst activity test equipment is outlined in Figure 15. Various catalyst samples such as plate type and honeycomb type catalyst samples from actual SCRs are tested using this equipment and other analysis devices for determination of catalyst activity, establishment of the method for catalyst life forecast and clarification of factors causing the catalyst activity deterioration. These studies are summarized in Table 10.

Results in the R&D activities up to now are as follows. In the field of determination of sample catalyst activities, the selection of standard conditions such as gas temperature, gas composition, NH_3/NOx mole ratio and area velocity have been decided in order to measure the NOx removal efficiency and the SO_3 conversion rate by the test equipment. Based on such achievements, we plan to continue investigations to find the method for catalyst life forecast.

As for the factors which cause catalyst activity deterioration, followings have been found.

- The reduction in specific surface area leads to catalyst activity deterioration.
- As to the change in pore size distribution, pores of size around 50Å in diameter decrease in low dust plate type catalysts while the ratio of pores of intermediate sizes around 100Å in diameter increases.
- From the adherent material analysis no attachment of poisoning alkali metal elements such as Na and K are recognizable on the surface of sample catalysts as far as being analyzed by a election probe micro analyzer (FPMA) although dust has deposited on the surface. Forced poisoning tests on catalyst samples have revealed, in addition, that the dust is somewhat responsible for catalyst activity deterioration and that the effect of potassium is large among alkali metals.
- As for the surface conditions, the attachment of dust to catalyst surface depends on the catalyst type and the place of catalyst installation in SCR reactor.
- As for the crystal structure, no change has been recognizable by X-ray analysis.

From the test results above mentioned, the change in catalyst surface conditions such as specific surface area and pore size distribution have close relation to catalyst activity deterioration in the case of SCR catalysts of Takehara Power Station.

6. CONCLUSION

EPDC has been playing pioneering roles among electric power utilities in Japan in the development and utilization of the SCR process for coal fired power plants since 1976 by its steady accumulation of experiences represented by the pilot tests, demonstration tests and more than 8 years of commercial operations of SCR plants. The SCR process is now used widely at about half of all coal fired power stations in Japan, and the SCR system now belongs to a well-matured technology in Japan. EPDC envisions for larger SCR systems, and a world's largest SCR unit will be completed in 1990. It has been demonstrated that SCR system is attractive in cost, and the system is getting more economical through technical innovations and competition among SCR manufacturers. EPDC continues its efforts on improvement of the SCR system including the establishment of a method for catalyst life management and further improvement of system economy.

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6. "The Operation Results of DeNOx System (SCR) for Unit No. 3 (700 MW) at Takehara Thermal Power Station, Japan", J. Watanabe, NOx Symposium Karlsruhe 1985, Karlsruhe, West Germany, February 1985

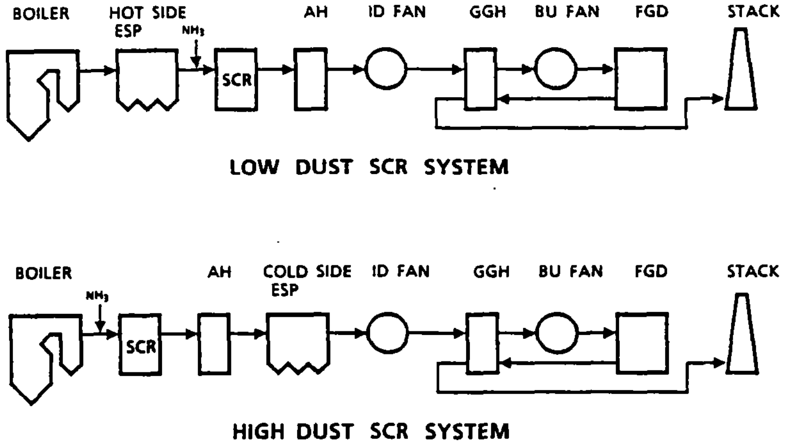

Fig. 1 Type of SCR System

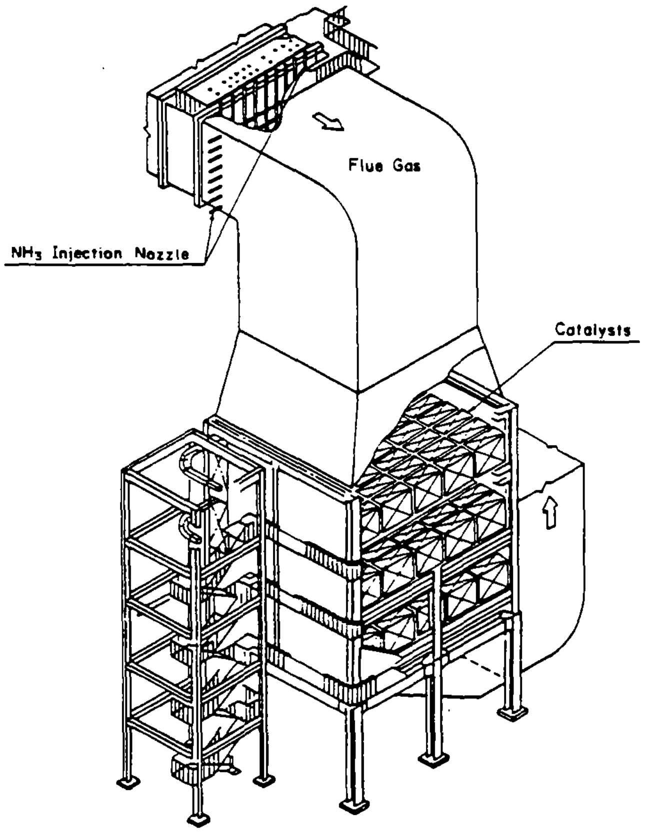

Fig. 2 Takehara #3 SCR Reactor

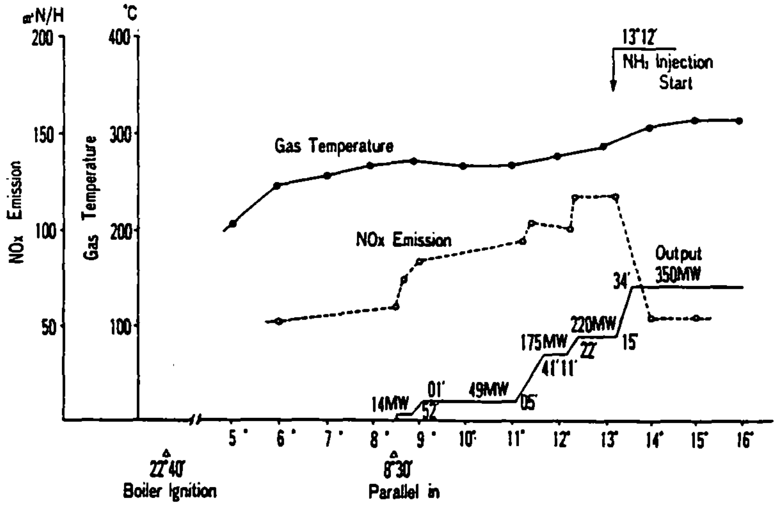

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Fig. 3 Start Up Record of Takehara #3

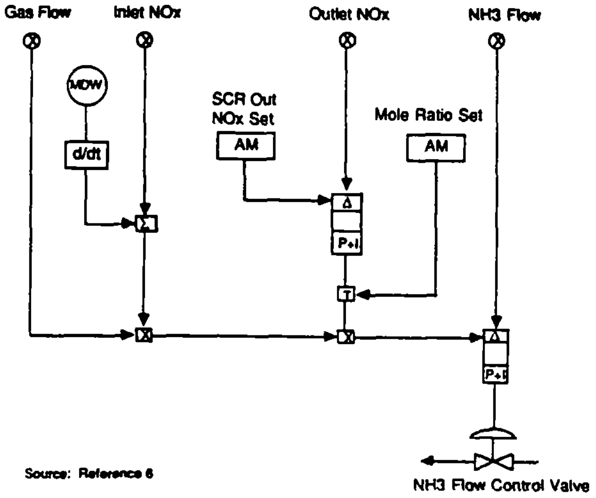

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Fig. 4. NOx Control System at Takehara #3

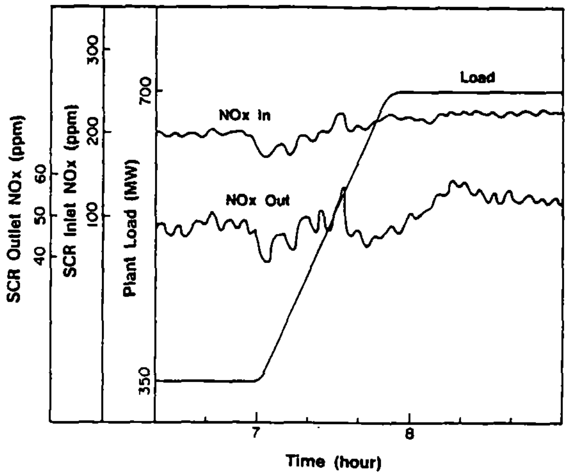

Fig. 5 NOx Control during Load Change

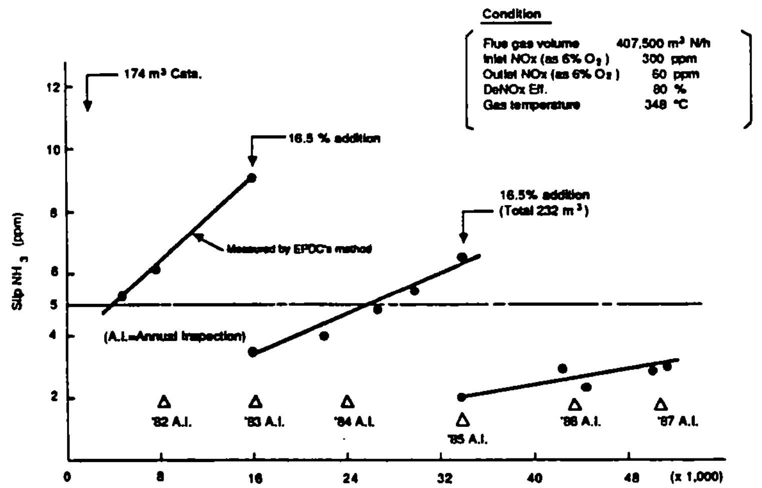

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Fig. 6. Slip NH_3 Trend at Unit No. 1 A-train

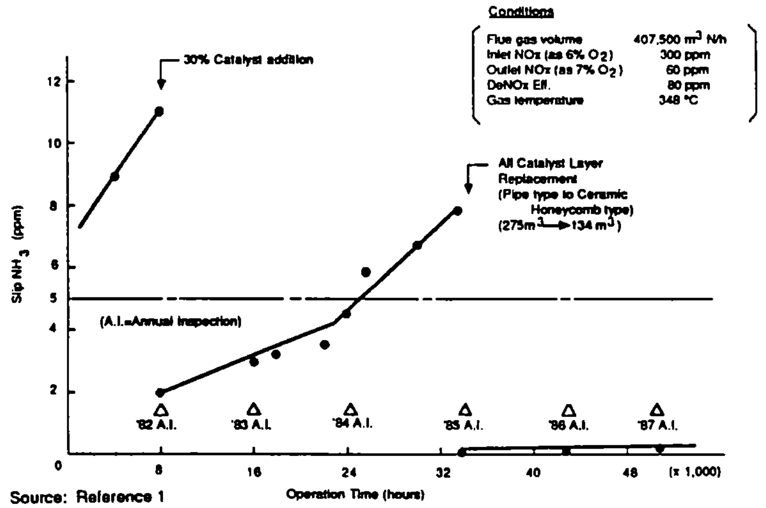

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Fig. 7. Slip NH_3 Trend at Unit No. 1 B-train

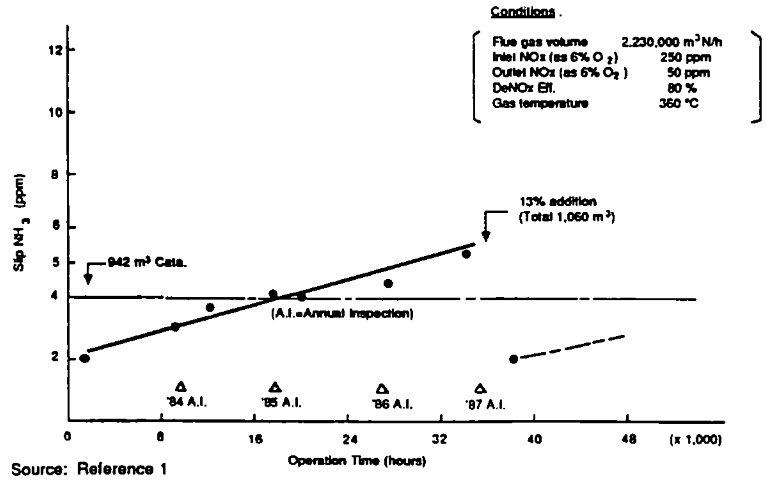

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Fig. 8. Slip NH_3 Trend at Unit No. 3

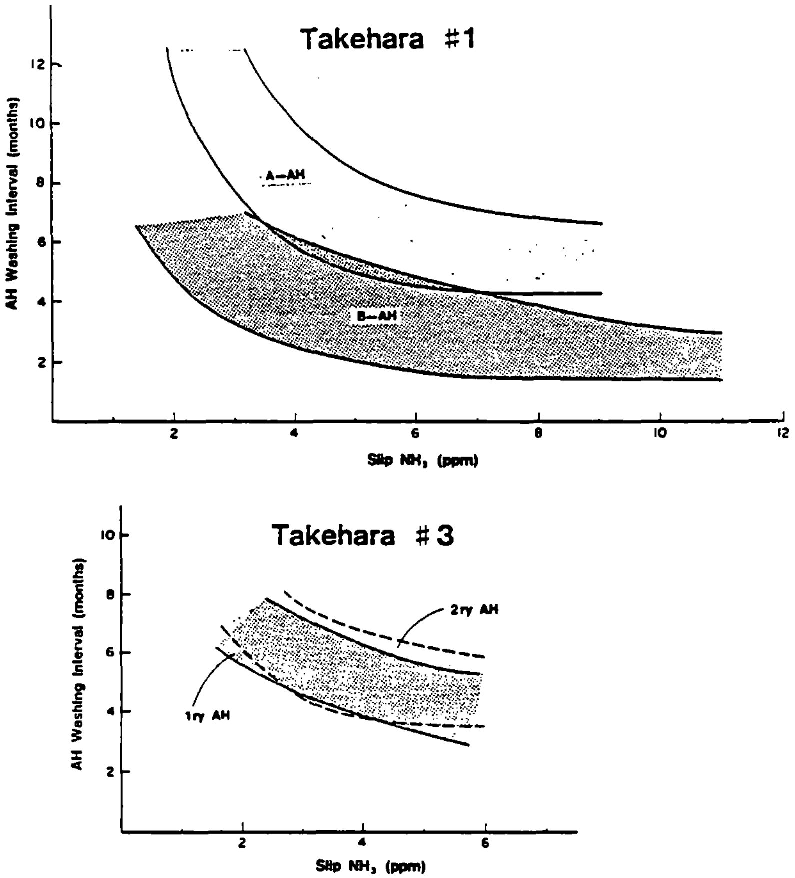

Fig. 9 Slip NH_3 vs. AH Washing Interval

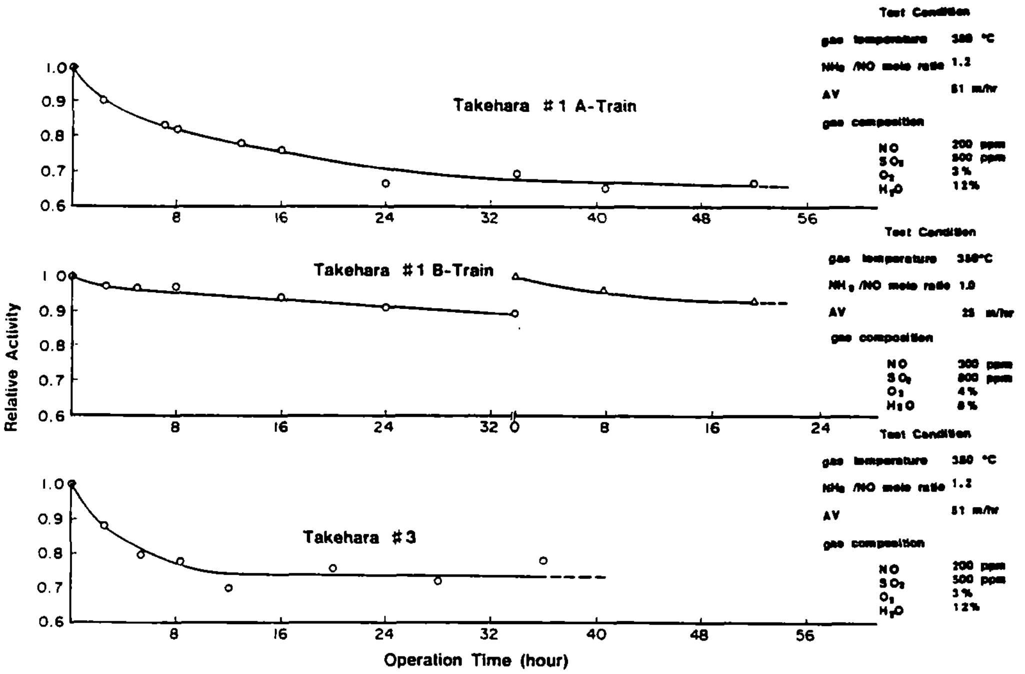

Fig. 10 Activity Deterioration of Sample Catalyst

Note: Direct comparison among above three graphs is inappropriate

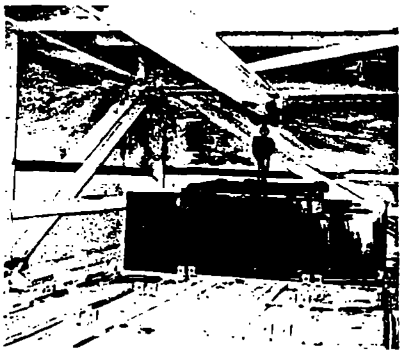

Photo. 1

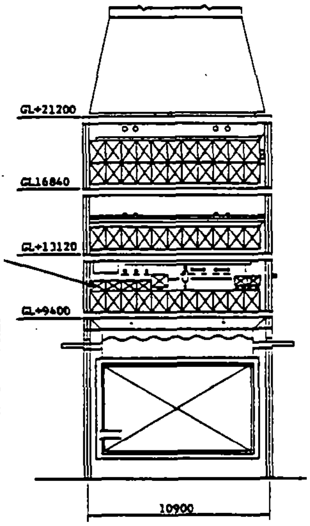

Fig. 11 Additional Catalyst at Takehara #3

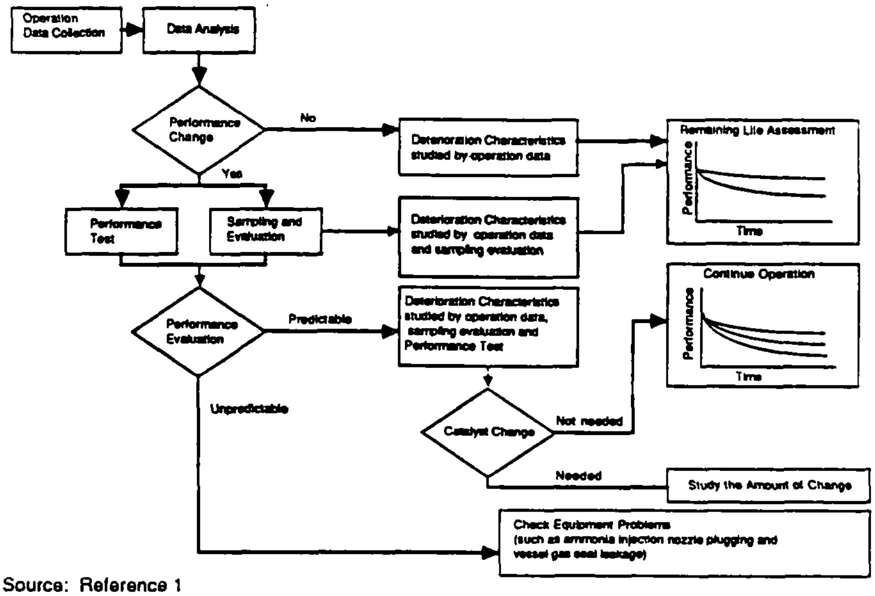

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Fig. 12. SCR Catalyst Performance Control Flow Diagram

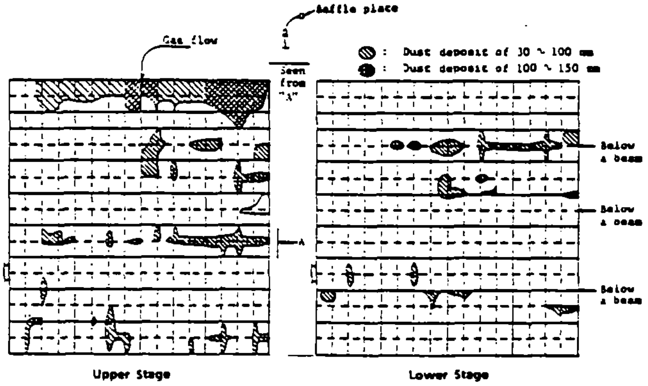

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Fig. 13 Dust Deposits on Catalyst Layers at #1 - A Train

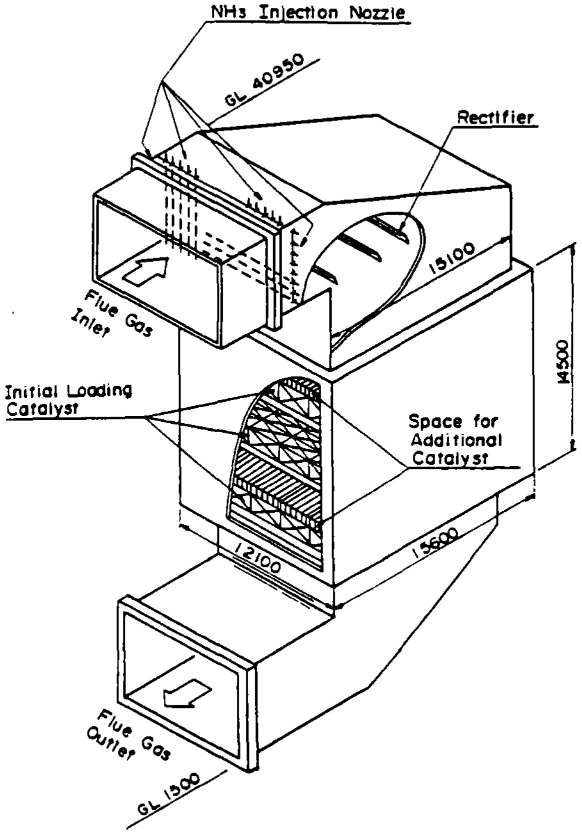


Fig. 14 Matsuura # 1 SCR Reactor

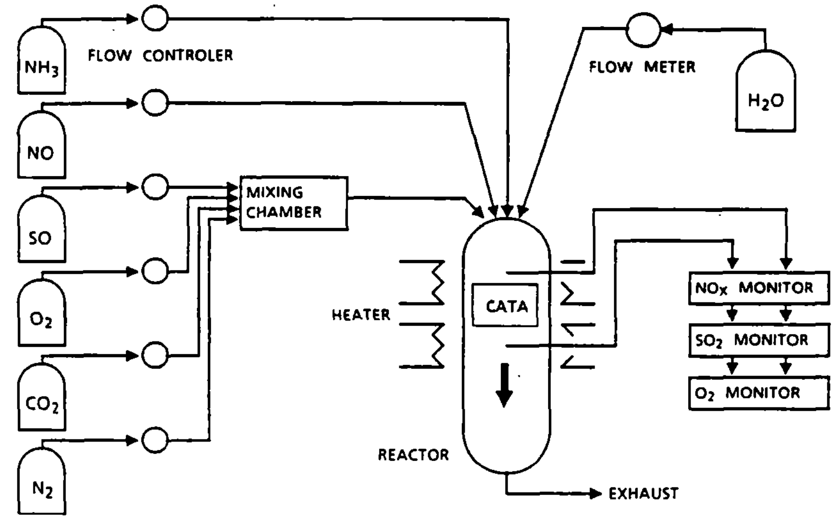


Fig. 15 Catalyst Activity Test Equipment

Table 1. SCR Specifications of Takehara #1 and #3

Train		Takehara #1 A/B	Takehara #3 A/B
Gas Volume	m^3 N/h	407,500 / 407,500	2,230,000
Gas Temperature	°C	329 - 348	360 - 380
NOx In	ppm (6 % O_2)	300	250
NOx Out	ppm (6 % O_2)	60	50
DeNOx Efficiency	%	80	80
SOx In	ppm	1,850	1,000
SO_3 Conversion	%	0.5 max.	0.5 max.
Slip NH_3	ppm (6 % O_2)	3.7/4.0	3.6
Catalyst Type	- - -	Plate (10 mm pitch)/ Honey comb (6mm opening)	Plate (10 mm pitch)
Catalyst Volume	m^3	232/134	1,060
Space Velocity	1 / h	1,760/3,037	2,110
Area Velocity	m / h	8.7/6.5	10.4
Linear Velocity	m / s	4.8/5.2	6.9
Reactor Dimension	m	8.5W x 8.5D x 10.8H	10.9W x 12D x 13H
Catalyst Stage	- - -	4 / 3	4.5

Table 2. Takehara #1-A SCR Performance Test Result

		Aug. 1985	Dec. 1985	Nov. 1986	Oct. 1987	Feb. 1988
Gas Volume	x 1,000 m^3 N/h	404	389	399	396	398
Gas Temperature	°C	343	344	352	341	348
NOx In	ppm (6 % O_2)	266	287	271	238	252
NOx Out	ppm (6 % O_2)	55	51	68	53	52
DeNOx Efficiency	%	79	82	75	78	79
Slip NH_3	ppm (6 % O_2)	7.2	2.3	1.3	2.8	2.5
Slip NH_3	ppm (design basis)*	6.6	1.9	2.9	2.7	3.0
SOx In	ppm	1,520	1,420	1,240	1,420	1,050
SO_3 In	ppm	4.0	4.4	5.3	2.1	3.4
SO_3 Out	ppm	5.0	4.8	5.7	2.5	3.8
SO_3 Conversion	%	0.07	0.04	0.03	0.03	0.04

* : calculated on the design basis described in Figure 6

Catalyst was replaced in the periodical inspection between September and November, 1985.

Table 3. Takehara #1-B SCR Performance Test Result

		Aug. 1985	Dec. 1985	Nov. 1986	Oct. 1987	Feb. 1988
Gas Volume	x 1,000 m^3 N/h	380	396	411	377	395
Gas Temperature	°C	333	343	354	343	340
NOx In	ppm (6 % O_2)	274	306	283	251	249
NOx Out	ppm (6 % O_2)	75	61	60	45	52
DeNOx Efficiency	%	73	80	79	82	79
Slip NH_3	ppm (6 % O_2)	8.1	0.1	0.1	0.2	0.1
Slip NH_3	ppm (design basis)*	6.8	0.1	0.1	0.2	0.1
SOx In	ppm	1,440	1,490	1,180	1,340	1,210
SO_3 In	ppm	4.3	5.2	4.9	3.2	2.8
SO_3 Out	ppm	19.0	7.6	7.4	3.2	4.6
SO_3 Conversion	%	0.75	0.18	0.21	0.08	0.15

* : calculated on the design basis described in Figure 7.

Catalyst was replaced in the periodical inspection between September and November, 1985.

Table 4. Takehara #3 SCR Performance Test Result

		Sept. 1985	Aug. 1986	Aug. 1987	Dec. 1987
Gas Volume	x 1,000 m^3N/h	2,140	2,318	2,346	2,364
Gas Temperature	°C	360	366	365	360
NOx In	ppm (6 % O_2)	246	228	245	226
NOx Out	ppm (6 % O_2)	51	53	45	44
DeNOx Efficiency	%	79	77	82	81
Slip NH_3	ppm (6 % O_2)	2.6	2.4	6.2	2.0
Slip NH_3	ppm (design basis)*	3.9	4.5	5.3	2.3
SOx In	ppm	221	205	405	200
SO_3 In	ppm	1.3	1.0	2.1	2.6
SO_3 Out	ppm	1.7	1.5	3.6	3.4
SO_3 Conversion	%	0.16	0.24	0.37	0.4
		30%	50%	70%	

* : calculated on the design basis described in Figure 8.

Catalyst was added in the periodical inspection between September and November 1987.

Table 5. Pressure Recovery by AH Washing

		Differential Pressure of AH (mmAq)	
		Before Washing	After Washing
Takehara #1	A-AH	90	60
	B-AH	70	55
Takehara #3	1ry AH	114	88
	2ry A-AH	95	70
	2ry B-AH	68	60

Table 6. Basic Consideration for AH Clogging

• AH Element	NF type layer in possible deposit areas
• Soot Blower	Reinforced blower such as retractable, twin or multi nozzle type
• Blowing Schedule	Increased blowing frequency, ex. 6 times/day

Table 7. SCR Specification of Matsuura #1

Design Basis		Max. Gas Vol. / Max. Inlet NOx
Gas Volume	x 1,000 m^3 N/h	3,100 / 3,029
Gas Tempeature	°C	370
NOx In	ppm (6 % O_2)	200 / 250
NOx Out	ppm (6 % O_2)	50
DeNOx Efficiency	%	75 / 80
SOx In	ppm	200 - 1,000
SO_3 In	ppm	3.5 max.
SO_3 Conversion	%	0.5 max.
Slip NH_3	ppm	2/3.5
Catalyst Type	—	Plate (10mm pitch)
Catalyst Volume	m^3	1,541
Space Velocity	1/h	2,010
Area Velocity	—	6.5
Linear Velocity	m/s	10
Reactor Dimension	m	12.1W x 15.6 D x 14.5 H
Catalyst Stage	—	3
Train	—	2

Table 8. Premises for Economic Evaluation

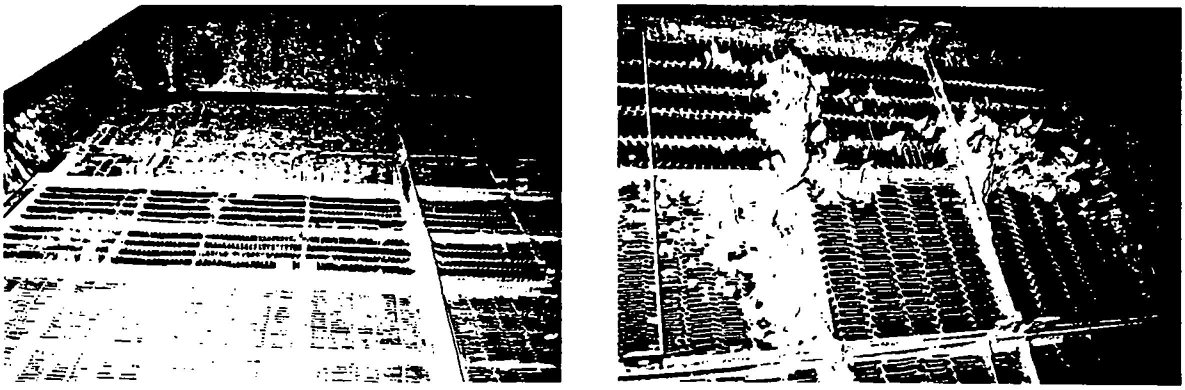
Plant Generating Capacity	350 MW x 1
Plant Efficiency	38.3 % (net)
Plant Use Factor	8.6 %
Annual Capacity Factor	70 %
Electricity Transmitted	1,961 GWh/year
Coal Calorific Value	6,200 kcal/kg JIS ad
Sulfur Content	1.2 %
Nitrogen Content	1.8 %
Ash Content	15 %
SCR Type	Low Dust System
NOx In/Out	300/60 ppm (80% DeNOx Efficiency)
Gas Volume	3,350 m^3 H/MWh
Space Velocity	2,000 1/h
Catalyst Life	4 years
Train	2
Ammonia Cost	$850/t
Currency Exchange Rate	Yen 130/$
Discount Rate	10 %
Escalation Rate	0 % pa
Depreciation Period	20 years

Table 9. SCR Cost [350 MW x 1 unit, 1989 value, 1$ = 130 Yen]

CONSTRUCTION COST	
Reactor and Ducting	$19/kW
Catalysts	29
Ammonia Injection System	4
Others (Electrical Equipment, C & I, Civil Works)	3
On-Site Engineering & Support Facilities	5
Interest during Construction	4
Home Office Fee	2
TOTAL CAPITAL REQUIREMENT	$66/kW
LEVERIZED BUS-BAR COST	
Capital	1.4 mill s/kWh
Operation and Maintenance	0.4
Catalyst Exchange	0.9
Ammonia	0.6
Other Utilities	0.2
Tax	0.1
TOTAL BUS-BAR COST	3.6 mill s/kWh

Table 10. R & D on SCR Catalyst

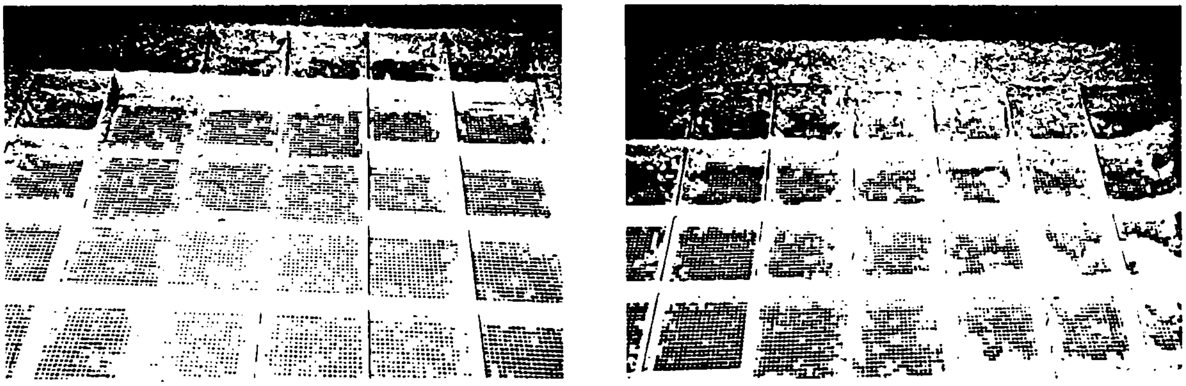
- Sample Catalysts Activity Test
- Catalyst Life Forecast
- Study on Factors in Catalyst Deactivation
  - Specific surface area .... - N_2 adsorption (BET)
  - Pore size distribution .... - Mercury method
  - Adherent material analysis.............. - Atomic absorption analysis
  - Surface state .... - SEM
  - Crystal structure .... - X-ray Analysis



Less Deposit Area

Much Deposit Area

Takehara #1 - A Train



Less Deposit Area

Much Deposit Area

Takehara #1 - B Train

Photo. 2 Ash Deposit at Takehara #1 SCR

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

SEP 23 1991

Mr. Preston Lewis
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Lewis:

Enclosed is a copy of the administrative record for the Prevention of Significant Deterioration (PSD) permit modification for the Orlando Utilities Commission (OUC). The public notice will be published in the Orlando Sentinel on September 29, 1991, and the administrative record of the modification request should then be available for review by the public during the 30 day public comment period of September 29 through October 29. Thank you for assisting us in this matter. If you have any questions, please contact me at (404) 347-5014.

Sincerely yours,

Scott Davis

R. Scott Davis
Source Evaluation Unit
Air, Pesticides, and Toxics
Management Division