

Manuscript

Title : New Flue Gas Treatment System for
1,050MWe Coal Fired Plant

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1. Introduction

Tachibana-Wan thermal power station was constructed in Anan-city, Tokushima Prefecture that is famous for its scenic beauty. Commissioning of the 2nd unit started in April, 2000 and its commercial operation commenced December 15, 2000. The Tachibana-Wan thermal power station is comprised of two coal-fired plants, each with a capacity of 1,050MW, making it the largest coal fired power station in Japan. Other features are its high efficiency and its adopting a new state of the art environmental technology through which emissions have been kept to an absolute minimum.

This paper introduces this new flue gas treatment system consisting of an Electric Static Precipitator (ESP), a Gas-Gas Heater (GGH) and Flue Gas Desulfurization (FGD) plant, all of which have been instrumental in achieving remarkable results for this power station.

2. Outline and Special Features of the Flue Gas Treatment System

The main specifications of the flue gas treatment system are listed in Table-1 and the plant is shown in Figure-1. A schematic flow diagram is shown in Figure-2.

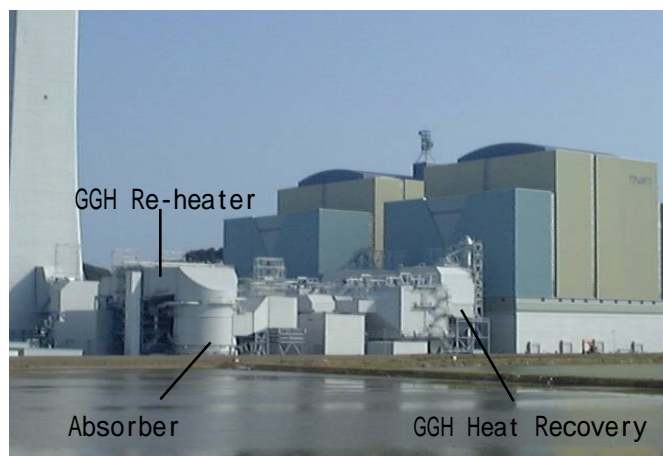


Figure-1 Overview of Flue Gas Treatment System for Unit No.2

Observing the most stringent laws for emission levels in Japan, our extensive expertise in the development and rationalization of an applicable system led to creating and adapting:

- A new flue gas treatment system
- A compact spray tower (Absorber)
- A heat medium forced circulated type GGH
- An on-line CaCO_3 analyzer
- A single stage gypsum dewatering system

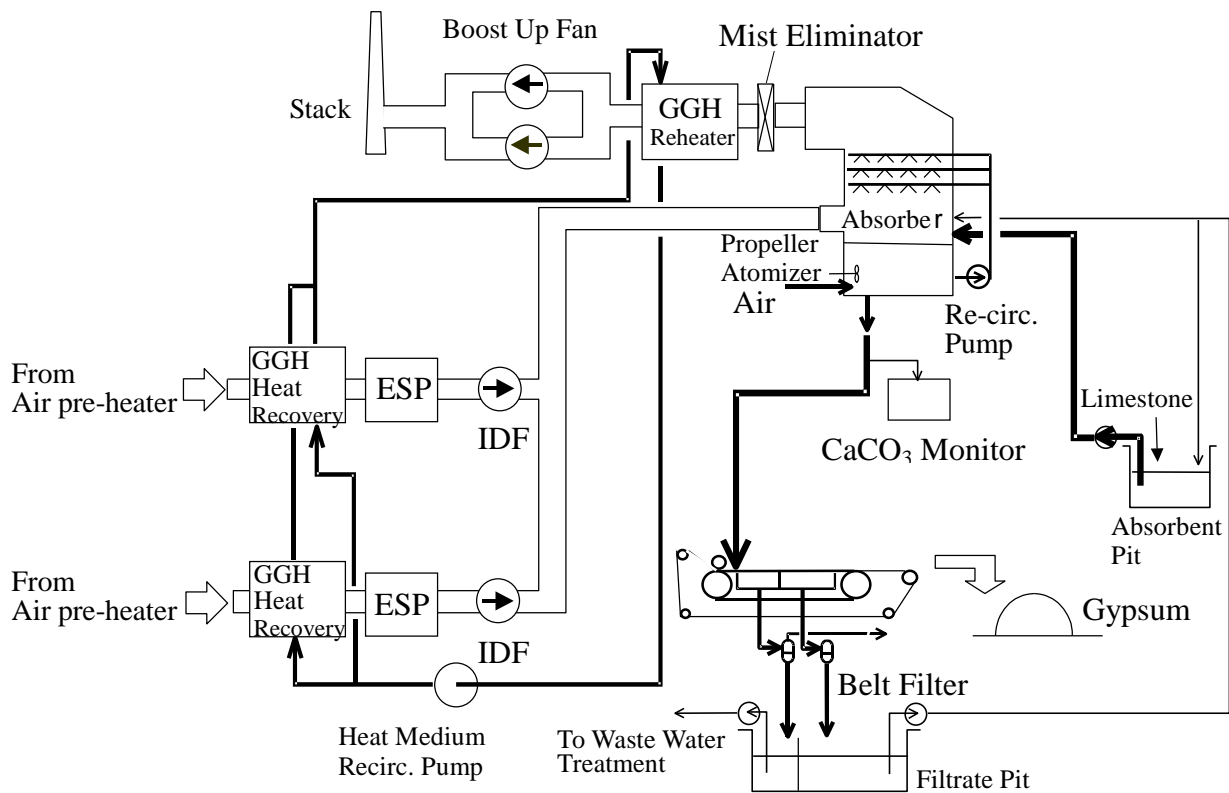


Figure-2 Schematic Flow Diagram

To achieve at the stack inlet, a dust concentration less than 10 mg/Nm^3 , a new flue gas treatment system was created that differs from conventional systems. Several new

technologies including an exceptionally compact design, higher SO₂ and dust removal efficiency such as high gas velocity, higher slurry concentration, etc. were adopted in the spray type absorber. For flexibility of plant operations and system simplification, new technologies were adopted for control & instrumentation of auxiliary equipment including a hot water forced circulation type GGH for heat transfer.

Table-1 Major Specifications of Flue Gas Treatment System of Unit No.2

Items	Specifications	
Capacity (MW)	1,050	
FGD	Wet Limestone-Gypsum Process	
GGH	Non Leak Type Heat Medium Forced Re-circulation hot water	
ESP	Low Temperature Type	
	Air Pre-heater Outlet	FGD Outlet
Flue Gas Flow Rate (Nm ³ /h) (SCFM)	3,330,000 (2,072,000)	3,470,000 (2,159,000)
Dust Conc. (mg/Nm ³) (grs/SCFD)	20,000 (8)	10 (0.004)
SO ₂ Conc. (ppm)	809	50
Gas Temp. (deg.C) (deg.F)	130 (266)	90 (194)

3. New Flue Gas Treatment System

A comparison between a conventional system and this new flue gas treatment system is shown in Figure-3. Dust is removed from flue gas by the ESP and FGD. In the conventional system where the heat recovery section of the GGH is located after the ESP, the optimum ESP outlet dust concentration is approximately 100mg/Nm³ at the GGH heat recovery section and after that dust is removed at the absorber up to 20mg/Nm³ which is the lowest possible dust emission capacity in conventional systems that has

been observed. According to our previous tests allowable dust concentration for GGH depends upon SO₃ concentration. Figure-4 shows the relationships between dust concentration and SO₃ concentration. In case the dust concentration is low, the flue gas becomes wet SO₃ condition as sufficient SO₃ is not absorbed on the dust and the wet SO₃ will attack the GGH materials. Therefore the ESP outlet dust reduction is limited so it may become unsuitable with respect to anti-plugging and anti-corrosion.

On the other hand, in the new flue gas treatment system the GGH heat recovery section is located upstream from the ESP and lowers flue gas temperature. The resistance of fly ash is lowered by this configuration and thus higher dust removal efficiency is obtained at the ESP. Although the heat recovery section of the GGH is exposed to very high amounts of dust and SO₃, SO₃ in the flue gas is condensed by reducing the temperature and the condensed SO₃ is neutralized by alkali in fly ash, thereby neither plugging nor depositions on fin tubes occurred in GGH heat recovery section. Around the heat recovery section of GGH, SO₃ is adsorbed into the fly ash easily and is removed by the ESP together with the dust. We found that the key to the removal of SO₃ is to control of GGH outlet gas temperature of heat recovery section.

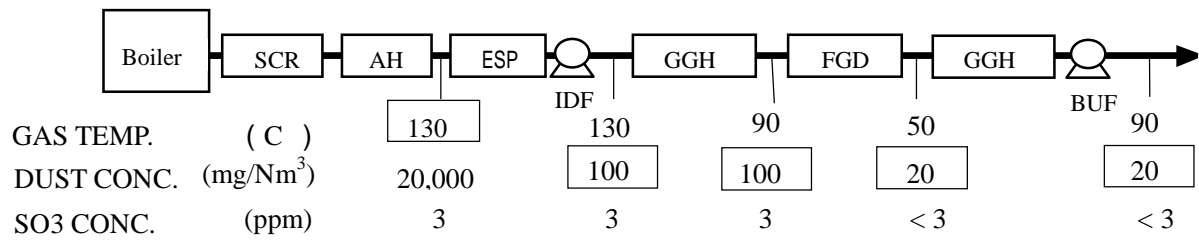
Not only the prevention of the visible gas from the stack but the selection of lower grade materials of GGH downstream equipment can be achieved in this system.

Moreover, in this new flue gas treatment system, ESP outlet dust concentration can be less than 50 mg/Nm³ without any negative effects and stack inlet dust emissions can be less than 10mg/Nm³ by the dust removal of spray type absorber. In the actual test results, the concentrations were less than 30 mg/Nm³ and 5mg/Nm³, respectively. In addition, a higher purity of gypsum is obtained due to the lower dust concentration.

These benefits along with high reliability of this new flue gas system were demonstrated during the pilot test at Matsuura power station in 1994. The picture of the pilot plant and schematic flow diagram is shown in Figure-5.

An additional benefit of this system is that higher mercury removal efficiency can be obtained. Mercury in the flue gas is removed by dust removal system and FGD system. Generally, the possible forms of mercury in the flue gas are elemental mercury, oxidized or ionic mercury. Elemental mercury is sub-micron and cannot be absorbed into the dust and water. Therefore the elemental mercury is difficult to remove the flue gas treatment system. On the other hand, oxidized or ionic mercury is easier to remove. For this reason, it is important to increase the ratio of oxidized or ionic mercury in the flue gas. At the boiler outlet, the form of mercury is mostly elemental. The elemental mercury is oxidized partially to the ionic mercury by the SCR catalyst. In addition, gas temperature influences the oxidation of mercury. In the new flue gas treatment system, heat recovery section of GGH is located upstream of dust removal system. Therefore the dust removal system inlet gas temperature can be controlled to maintain the suitable range with a view to the mercury removal. According to the pilot test, ESP inlet, the content of ionic mercury is more than 80 % in this system. As the result of the other commercial plant data, which was supplied recently, higher mercury removal efficiency can be achieved at ESP in this system.

CONVENTIONAL SYSTEM



NEW FLUE GAS SYSTEM

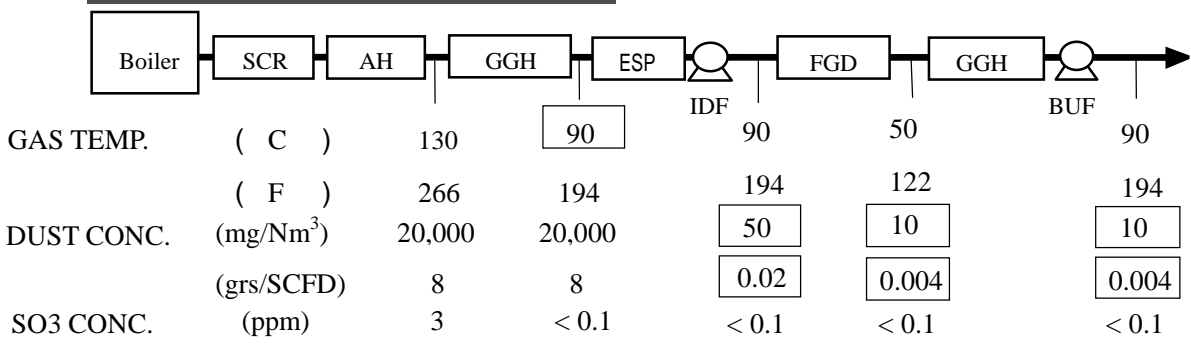


Figure-3 Comparison on Flue Gas System

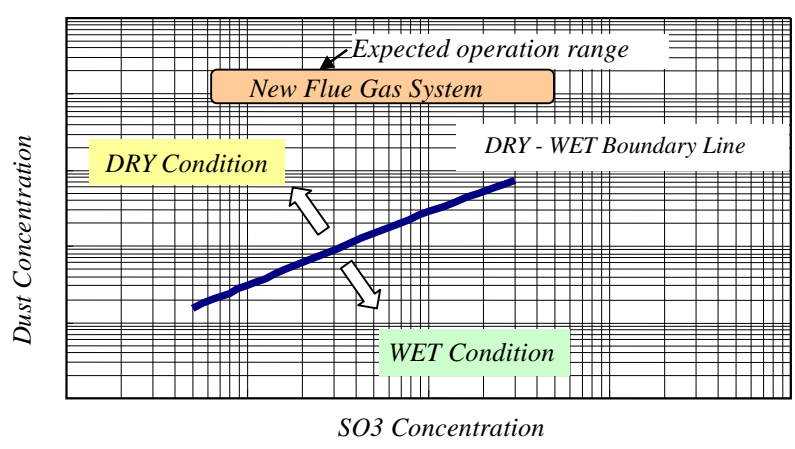
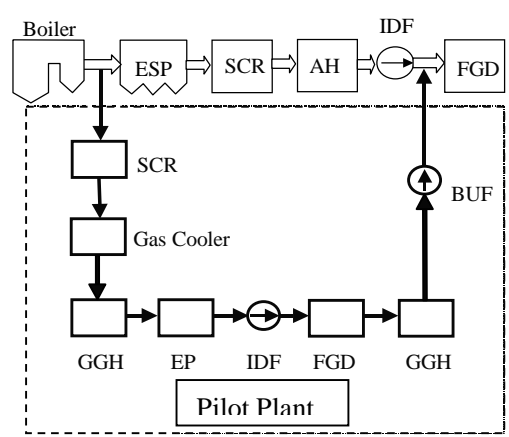


Figure-4 The relationship between dust concentration and SO3 concentration



Overview of Pilot Plant



Flow Diagram

Figure- 5 Pilot Plant Test for New Flue Gas Treatment System at EPDC/Matsuura Power Station Unit No.1

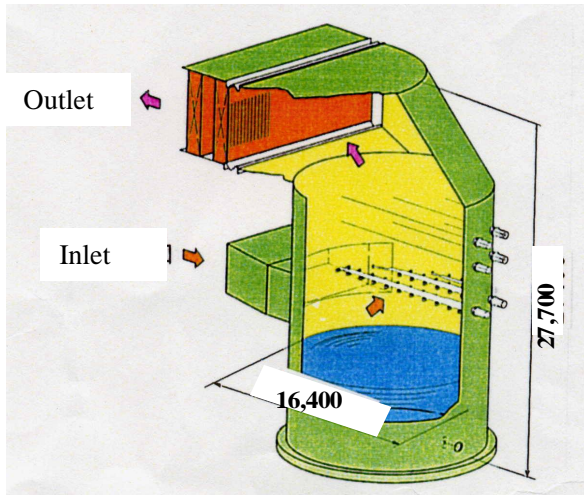
4. Compact Absorber

Babcock-Hitachi K.K. commercialized a single loop type spray absorber at No.1 unit Matsuura power station in 1990, being the first dust mixing in-situ oxidation FGD plant in Japan. Based on this absorber design, new technologies were incorporated into the compact design shown in Figure-6. The linear gas velocity in the absorber is 5m/s which is a remarkably higher velocity than previously applied in this FGD plant contributing to the higher SO₂ removal efficiency.

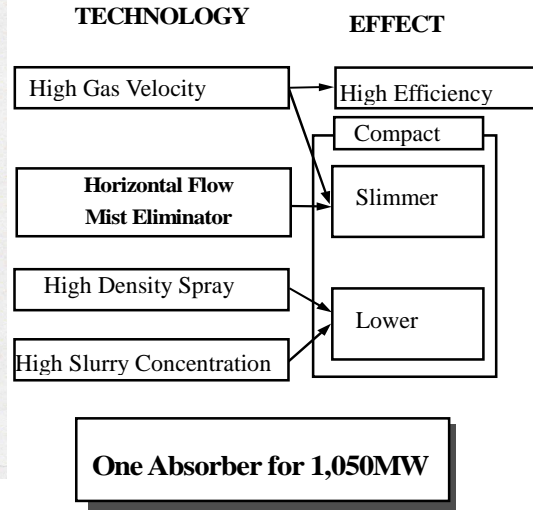
At our pilot plant we found that;

- There was no velocity dependence below 3 m/s of SO₂ removal efficiency.
- Higher gas velocity improves SO₂ removal efficiency.

We have evaluated mass transfer coefficients of the gas and liquid side at the pilot plant and found that not only gas mass transfer but also liquid mass transfer was improved. To clarify this improvement of liquid mass transfer, we conducted the test shown in Figure-7. This test measures behavior of solid particles in the water droplets utilizing a laser. In the relationship between gas velocity and particle velocity in Figure-7, we found that a higher gas velocity enhances the mixing of droplets inside, i.e. surface renewal. However, as increasing absorber gas velocity may lead to gas mal-distribution, the gas flow pattern was confirmed by CFD and a flow model test. All internals inside the absorber, such as spray headers, internal supports, nozzles, etc. were modeled by CFD for the examination to gain a full understanding of the flow patterns.



Construction of Absorber



Adopted Technology and those Effects

Figure- 6 Absorber cConstruction

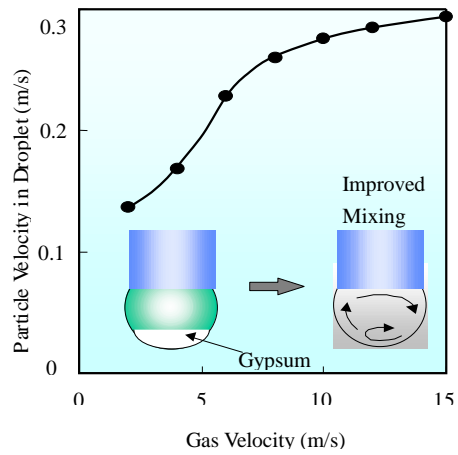
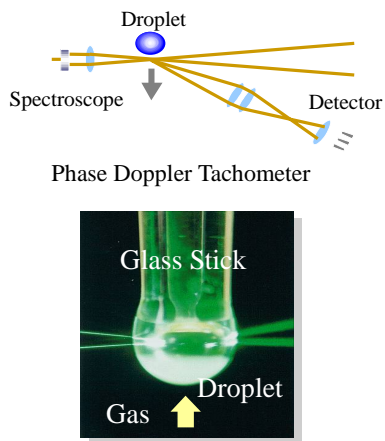


Figure- 7 Particles' Behaviors in Spray Droplet

5. Heat Medium Forced Circulated GGH

The non-leakage type GGH for the flue gas treatment system utilizes a pump forced hot water circulation system. Certain considerations for the application of this type of GGH to the flue gas system are shown in Figure-8. As the heat recovery section of the GGH is located upstream from the ESP and exposed to very high dust conditions, ash erosion and dust plugging were given particular consideration. A newly developed Shot Cleaning System employing 6mm steel balls was adopted for dust removal system. To avoid ash erosion from high dust concentration, optimization of gas velocity and tube arrangements were achieved through careful study. To prevent corrosion in the heat recovery section and equipment downstream as a result of possible lower inlet temperature in the winter season and other possible influences, the outlet temperature of the heat recovery section is kept constant by controlling the circulation flow of the heat medium. In choosing materials for the reheating section, corrosion from sulfuric acid and Stress Corrosion Cracking (SCC) were taken into account as the reheating section is located downstream from the Absorber and exposed to low pH corrosive entrained mists containing high chlorides.

Figure-9 shows the time dependence of GGH pressure loss. The state of the heating tubes after 2 years of operation is shown in Figure-10. Even after 2 years of operation, the increase of pressure loss is negligible. Therefore water washing of the GGH was not required through the 2 years operation.

The GGH was fabricated at the factory, including supports, insulation and auxiliary equipment to minimize costs and erection time at the site. Figure-11 shows the transportation of GGH modules from the factory.

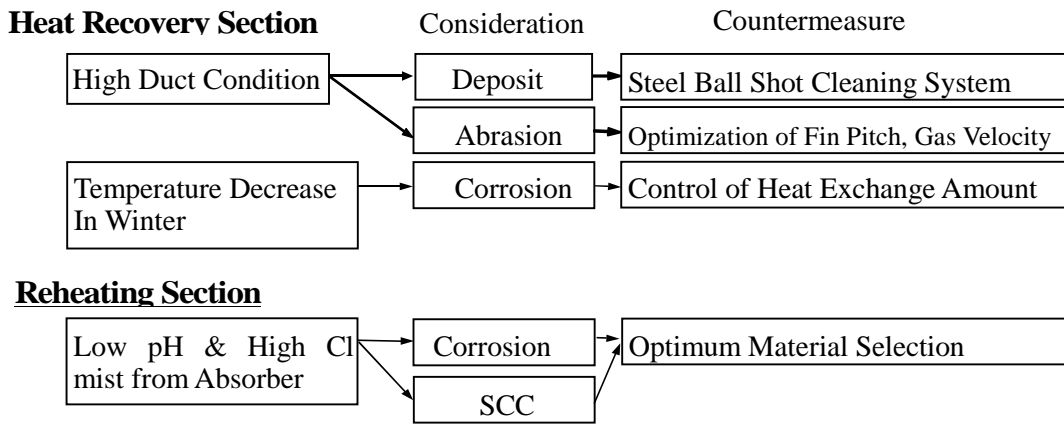
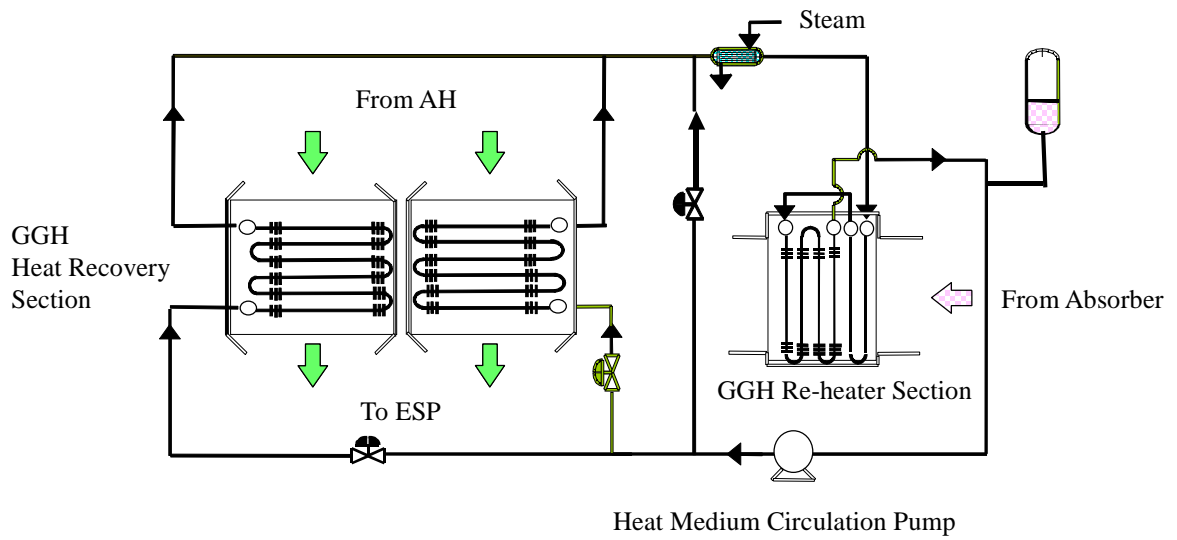


Figure- 8 Consideration & Countermeasure for GGH Design

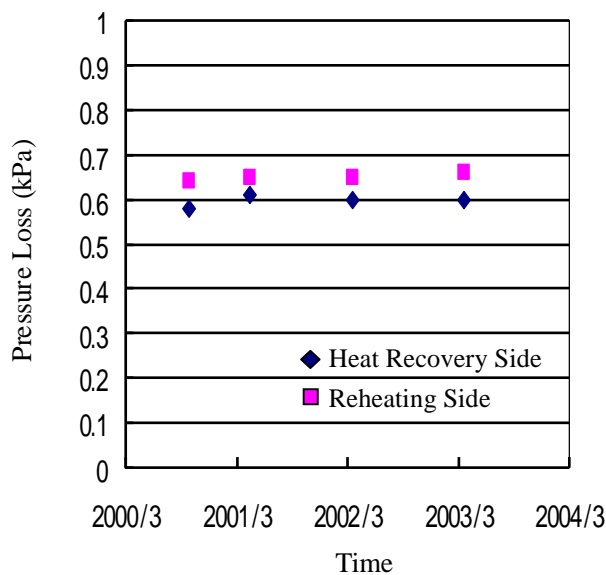


Figure-9 Transition of GGH Pressure Loss



Figure-10 The state of the heating tubes (After 2 years of operation)



Figure-11 Transportation of GGH Modules

6. Other Technologies Applied

6.1 On-line CaCO_3 Analyzer

CaCO_3 concentration in the Absorber slurry dominates SO_2 removal efficiency. As it was impossible to continuously monitor CaCO_3 concentration in the Absorber slurry, the slurry pH is normally monitored instead of CaCO_3 concentration and used for limestone slurry feed rate control. Babcock-Hitachi K.K. has developed and commercialized an on-line CaCO_3 analyzer during the demonstration test at No.1 unit of Matsuura power station, EPDC in 1997.

The principles of the analyzer are to ensure that;

- 1) A sufficient amount of acid is added to the slurry.
- 2) Additional acid reacts with CaCO_3 in the slurry and CO_2 is generated in proportion to the CaCO_3 concentration in the slurry.
- 3) Dissolved CO_2 analyzer continuously monitors CO_2 in the slurry. As the dissolved CO_2 generated by reaction between CaCO_3 and acid is monitored directly without producing CO_2 gas, the accuracy of slurry sampling is not necessary and reliable monitoring can be achieved with a simple analyzer.

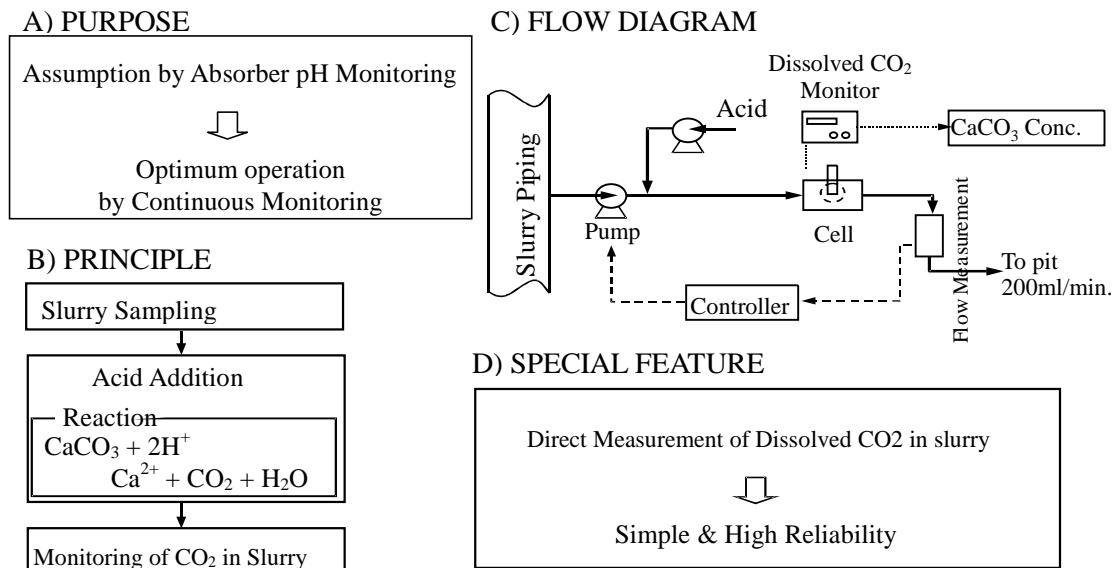


Figure- 12 Outline of CaCO₃ Monitor

6.2 Single Stage Gypsum Dewatering System

In Japan a batch type centrifuge was adopted traditionally to the gypsum dewatering system. However due to increased plant capacity, a continuous belt filter type is applied. In the belt filter system a hydro-cyclone or thickener was traditionally adopted for preliminary dewatering (pre-dewatering) before the belt filter. However, higher concentrations of absorber slurry enables the system to omit pre-dewatering thereby simplifying the system as well as providing for easier operation and maintenance. In this dewatering system all absorber bleed slurry is dewatered by a belt filter, suspended solids in the filtrate are very low, i.e. less than 3,000mg/l, instead of 30,000mg/l of hydro-cyclone overflow.

7. Operational Data during Commissioning

7.1 Performance Test Results

The main results during the performance test are shown in Table-2. Stringent dust emission levels at the stack, 10mg/Nm³ were achieved and actual test results were less

than 5 mg/Nm³ without a wet ESP. As for SO₂ emissions, instead of the required 50ppm rate at the stack inlet, a rate of 10 ppm was realized, proving the value of the compact absorber philosophy.

Stack inlet temperatures also fulfilled the required allowable temperatures without any deterioration.

Table-2 Main Test Results at Performance Test

ITEM	DESIGN	ACTUAL
ESP Inlet Dust Conc. (mg/Nm ³) (grs/SCFD)	20,000 (8)	17,600 (7)
Stack Inlet Dust Conc. (mg/Nm ³) (grs/SCFD)	10 (0.004)	< 5 (<0.002)
Absorber Inlet SO ₂ Conc. (ppm)	809	420
Stack Inlet SO ₂ Conc. (ppm)	50	10
Stack Inlet Temperature (deg.C) (deg.C)	90 (194)	92 (198)

7.2 Other Test Results

(1) On-line CaCO₃ Analyzer

Figure-13 shows a comparison between manual measurements (according to Japanese Industrial Standards method) and on-line data obtained from the analyzer together with demonstration test data. As shown the Figure-10, the analyzer is very reliable.

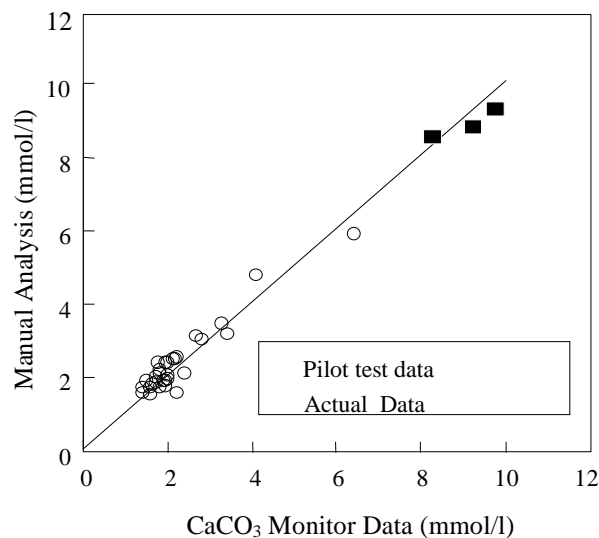


Figure-13 Comparison between Manual and CaCO₃ Monitor

(2) Gypsum Properties

Table-3 shows properties of gypsum obtained during the commissioning run and a microphotograph is shown in Figure-14. All required parameters were fulfilled, and due to a continuous on-line monitoring of CaCO_3 levels in the gypsum were kept very low.

Table-3 Gypsum Properties

ITEM	DESIGN	ACTUAL
Purity (%)	90	99
Surface Moisture (%)	10	8
CaCO_3 (%)	1.1	0.1
$\text{CaSO}_3 \cdot 1/2 \text{H}_2\text{O}$ (%)	0.2	0.1

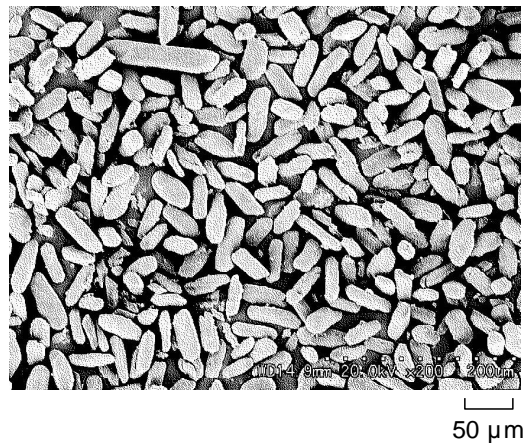


Figure- 14 Microphotograph of Gypsum

8. Conclusion

The latest compact air pollution control design was commissioned at unit No.2 of the Tachibanawan power station. All required design requirements were exceeded and the economical air pollution control system performed very reliably.

Further improvements for new and existing plants continue with a view to higher efficiency with minimal environmental impact.