4.2.2 Technical Comparison of Evaluated FGD Methods

The following technical items, which are considered important, are described for each evaluated FGD method for general comparison:

(1) Basic Principles of the Process
(2) Reactions
(3) Desulphurization Performance
(4) Dust Removal Performance
(5) Technical Levels
(6) Experience at Coal Fired Utility Plants
(7) Reliability
(8) By-products
(9) Utilities
(10) Waste Water
(11) Stack Lining and Flue Gas Reheating
(12) Operability
(13) Maintenability

Table 4.2-1 shows results of general technical comparison of the FGD methods evaluated in this study.

In addition, basic processes of such FGD methods are outlined as follows.

(1) Wet Type Limestone-gypsum Process - Spray Tower Method

Limestone ($CaCO_3$) slurry is sprayed to flue gas in a spray tower to absorb sulphur oxides (SOx) of the flue gas for desulphurization. The limestone slurry thus sprayed reacts with absorbed sulphur oxides and forms calcium sulphite ($CaSO_3$). Calcium sulphite thus formed is oxidized further and discharged in the form of gypsum ($CaSO_4$).

Major reactions which occur in this method are as follows:

[Absorption]

$$CaCO_3 + SO_2 + \frac{1}{2}H_2O \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O + CO_2$$

[Oxidation]

$$CaSO_3 \cdot \frac{1}{2}H_2O + \frac{1}{2}O_2 + 1\frac{1}{2}H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

The flow of these reactions is shown in Fig. 4.2-2.

The process flow of this method is shown in Fig. 4.2-3. This method consists of a draft system, a limestone slurry preparation system, an absorbing system, a gypsum recovery system, etc.

a. Draft system

The flue gas from boiler is pressurized by a boost-up fan (BUF), subjected to heat exchange at a gas to gas heat exchanger (GGH) with treated gas from FGD outlet, and enters the spraying absorber. Here, the flue gas temperature is lowered to the saturation temperature by spraying part of the absorber circulating liquid. The cooled flue gas is then uniformly dispersed and rectified in the absorber, comes into contact, face to face, with slurry at the absorbing portion, where sulphur oxides in the flue gas are absorbed and dust in the flue gas is removed by the scrubbing in the absorber.

After the desulphurization, mist included in the flue gas are removed at the mist eliminator which is existing at the upper part of the spraying tower.

After removal of sulphur oxides and dust, the treated flue gas is led again to the GGH, where it is heated by flue gas from boiler, and then discharged from the stack.

b. Limestone slurry preparation system

Limestone (powder), used as absorbent is stored in a limestone powder silo. The limestone powder is fed to a limestone slurry tank through a limestone metering feeder. Water is also added to the limestone slurry tank at a specified rate. Limestone powder and water are made into limestone slurry, and the limestone slurry is kept in the limestone slurry tank. Necessary amounts of limestone slurry are pumped from the tank by limestone slurry pumps to a circulation tanks existing at the bottom of the absorber. Waste water of gypsum dehydration is usually used for preparing the limestone slurry.

c. Absorbing system

The absorbing system, where the mixed slurry of limestone and reaction products is sprayed in the absorber, is the most important system on the desulphurization and the dust removal efficiency of the FGD. The mixed slurry sprayed in the absorber falls while absorbing and removing sulphur oxides and dust of the flue gas and the slurry is stored in the circulation tank existing at the bottom of the absorber. Limestone slurry is added to the tank to maintain the desulphurization performance of the mixed slurry, and the mixed slurry is sprayed again in the absorber tower for desulphurization. The air is blown into the absorber circulation tank to oxidize calcium sulphite into gypsum (calcium sulphate).

d. Gypsum recovery system

When gypsum is to be recovered as a by-product, the gypsum slurry from the absorption system is dehydrated by dehydrators to obtain gypsum in this system. Waste water from dehydrators is usually used again as make-up water for the desulphurization process.

(2) Wet Type Limestone Gypsum Process - Jet Bubbling Method

In this method, the flue gas and the air for oxidation are blown into an absorption liquid of limestone slurry in a jet bubbling reactor (JBR). Sulphur oxides included in flue gas are absorbed and oxidized in this way, and gypsum is recovered as a by-product.

The major reaction which occurs in this method is as follows:

[Absorption and oxidation]

$$CaCO_3 + SO_2 + \frac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O + CO_2$$

The flow of this reaction is shown in Fig. 4.2-4.

The process flow of this method is shown in Fig. 4.2-5. This method consists of a draft system, an absorbing system, a limestone slurry preparation system, a gypsum recovery system, etc.

a. Draft and absorbing system

The flue gas from boiler is pressurized by a boost-up fan (BUF), subjected to heat exchange at a gas to gas heat exchanger (GGH) with treated gas from FGD outlet, and part of the makeup water is sprayed to lower the flue gas temperature to the saturation temperature.

The flue gas of saturation temperature is led to the JBR and blown into the absorption liquid through sparger pipes, and sulphur oxides and dust are absorbed and removed from the flue gas.

Mists included in the flue gas at desulphurization are removed at a subsequent mist eliminator. After desulphurization and dust removal, the treated flue gas is led again to the GGH, where it is heated by flue gas from boiler, and then discharged from the stack.

b. Limestone slurry preparation system

Limestone (powder), used as absorbent is stored in a limestone powder silo. The limestone powder is fed to a limestone slurry tank through a limestone metering feeder. Water is also added to the limestone slurry tank at a specified rate. Limestone powder and water are made into limestone slurry, and the limestone slurry is kept in the limestone slurry tank. Necessary amounts of limestone slurry are pumped by limestone slurry pumps and fed to the JBR. Usually, waste water of gypsum dehydration is used as water for making the limestone slurry.

c. Gypsum recovery system

When gypsum is to be recovered as a by-product, the gypsum slurry from the JBR is dehydrated by dehydrators to obtain gypsum in this system. Waste water from dehydrators is usually used again as make-up water for the desulphurization process.

(3) Spray Dryer Method

In the spray dryer method, slaked lime slurry is sprayed in the form of very fine droplet in flue gas in a spray dryer absorber (SDA) to absorb sulphur oxides of the flue gas.

Water in the slurry evaporates by the heat of the hot flue gas. Sulphur oxides in flue gas reacts, at the same time, with slaked lime ($Ca(OH)_2$) of the slurry, resulting a dry powder mixture of calcium sulphite ($CaSO_3$) and gypsum ($CaSO_4$), which falls on the bottom of SDA or is collected and removed by a subsequent dust collector.

Major reactions which occur in this method are as follows:

[Absorption]

$$Ca(OH)_2 + SO_2 + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O + H_2O$$

[Oxidation]

$$CaSO_3 \cdot \tfrac{1}{2}H_2O + \tfrac{1}{2}O_2 + 1\tfrac{1}{2}H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

The flow of these reactions is shown in Fig. 4.2-6.

The process flow of this method is shown in Fig. 4.2-7. This method consists of a draft system, a slaked lime slurry preparation system, a slurry spraying system, a dust recirculation system, etc.

a. Draft system

The flue gas from boiler is led to SDA usually by an induced draft fan (IDF). The absorbent is sprayed in the SDA and sulphur oxides are removed. The temperature of the flue gas in the SDA is adjusted to an optimal operating temperature range by the amount of concentration-adjusted slaked lime slurry sprayed in the SDA. The temperature of flue gas for optimal operation is controlled to be higher than the saturation temperature by 10 to 20°C so that the flue gas can be in a dry state. The reaction products generated in the flue gas are partly removed by the cyclone separation effect of the SDA. The rest of the reaction products is carried to a subsequent dust collector, where the dust including the reaction products are removed to achieve a level of concentration which meets regulations, and the treated flue gas is discharged from the stack.

b. Slaked lime slurry preparation system

Slaked lime or quick lime, used as absorbent, is stored in a storage silo, and fed to a slaked lime slurry tank through a slaked lime metering feeder. Water is also added to the tank at a specified rate to make supplied slaked lime into slurry and store it in the slurry form.

c. Slurry spraying system

The slurry spraying system sprays the absorbent slurry in the SDA. The absorbent slurry is a mixture of the slaked lime slurry and part of the reaction products fallen to the bottom of the SDA and collected at the subsequent dust collector.

The absorbent slurry must be sprayed in the form of very fine droplet, and rotary atomizers are used for that purpose in large scale systems.

d. Dust recirculation system

The dust recirculation system removes the reaction products fallen to the bottom of the SDA and collected at the subsequent dust collector, and recirculates part of the reaction products to the absorbent slurry to improve the utilization rate of slaked lime used in the method.

(4) Limestone Injection into Furnace Method

In this simplified FGD method, limestone ($CaCO_3$) is blown into the high temperature region (about 1,100°C) of furnace to decarbonate limestone and partly absorb sulphur oxides at the same time. In addition, water is sprayed in a reactor, installed at a low temperature region downstream of the air preheater, for further desulphurization when it is necessary to get better deSOx efficiency. The by-product along with dust is collected at following dust collector.

Desulphurizing reactions occur in the furnace and the reactor when water spray tower is applied. Reactions which occur in the furnace and water spray tower are as follows:

[Reactions in furnace]

$$CaCO_3 \rightarrow CaO + CO_2$$
$$CaO + SO_2 + \frac{1}{2}O_2 \rightarrow CaSO_4$$

[Reactions in reactor]

$$CaO + SO_2 + \frac{1}{2}H_2O \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O$$

$$CaO + SO_2 + \frac{1}{2}O_2 + \frac{1}{2}H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

$$SO_2 + H_2O \rightarrow H_2SO_3$$

$$CaO + H_2SO_3 \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O + \frac{1}{2}H_2O$$

A flow diagram of these reactions is shown Fig. 4.2-8, and the process flow of this method is shown in Fig. 4.2-9.

(5) Slaked Lime Injection into Duct Method

In this simpliflied FGD method, an absorbent of slaked lime ($Ca(OH)_2$) is blown into the duct at a low temperature region following the air preheater. In addition, water is sprayed in a subsequent reactor for furhter desulphurization when it is necessary to get better deSOx efficiency. Slaked lime is used as absorbent because of its high reactivity. The by-product along with dust is collected at following dust collector.

Reactions which occur in this method are as follows:

[Reactions in duct]

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O + \frac{1}{2}H_2O$$

$$Ca(OH)_2 + SO_2 + \frac{1}{2}O_2 + H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

[Reactions in reactor]

$$SO_2 + H_2O \rightarrow H_2SO_3$$

$$Ca(OH)_2 + H_2SO_3 \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O + 3/2\ H_2O$$

A flow diagram of these reactions is shown Fig. 4.2-10, and the process flow of this method is shown in Fig. 4.2-11.

(6) Activated Coke Method

In the activated coke method, activated coke used as absorbent is filled in an moving bed type absorber in which activated coke moves by gravitation. Flue gas is passed through the absorber for absorption of sulphur oxides.

As the absorption efficiency of the absorbent deteriorates gradually, the absorbent is continuously heated for regeneration in a desorber. Sulphuric acid or sulphur is recovered as a by-product.

The absorption and regeneration reactions which occur in this method are as follows:

[Absorption]

$$1/2O_2 + [AC] \rightarrow Oad \cdot [AC]$$
$$SO_2 + Oad \cdot [AC] \rightarrow SO_3ad \cdot [AC]$$

[Regeneration]

$$SO_3ad \cdot [AC] + 1/2(C) \rightarrow SO_2 + 1/2CO_2 + [AC]$$

The flow of the absorbing reaction is shown in Fig. 4.2-12

The process flow of this method is shown in Fig. 4.2-13. This method consists of a draft system, an absorption system, a regeneration system, a by-product recovery system, etc.

a. Draft system

The flue gas is passed through the moving bed type absorber, which is filled with activated coke and in which the absorbent moves by gravitation, so that sulphur oxides of the flue gas is absorbed.

b. Absorption system

The absorbent (activated coke) is fed to the top of the absorber and then the absorbent is flowed down by gravity from the top of the absorber to the bottom of it.

During the moving action, the flue gas from boiler is passed horizontally through the moving bed (cross-flow contact) and sulphur oxides are absorbed. The used absorbent is regenerated in the desorber, and then fed to the absorber again.

c. Regeneration system (Desorption system)

The used absorbent (activated coke) from the absorber, which absorbed sulphur oxides, is regenerated in the desorber for reuse. In regeneration, the used absorbent is heated to about 400°C to free SO_2-rich gas from the used absorbent at the desorber.

d. Recovery system

The recovery system recovers by-product from the SO_2-rich gas freed in the regeneration system. The by-product is recovered in the form of sulphuric acid or elemental sulphur.

(7) Electron Beam Method

Such radicals as OH, O and HO_2 are generated in flue gas by electron beam irradiation, and SOx are oxidized and absorbed by such radicals. Nitrogen oxides are also absorbed at the same time, and they undergo neutralizing reactions with ammonia (NH_3) which is injected in flue gas, and recovered as by-products in the forms of ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3).

Oxidation and neutralization reactions in the process are as follows:

[Oxidation]

$$SO_2 \xrightarrow{OH} HSO_3 \xrightarrow{OH} H_2SO_4$$

$$SO_2 \xrightarrow[O]{} SO_3 \xrightarrow[H_2O]{} H_2SO_4$$

[Neutralization]

$$H_2SO_4 + 2NH_3 \rightarrow (NH_4)_2SO_4$$

A flow diagram of these reactions is shown Fig. 4.2-14, and the process flow of this method is shown in Fig. 4.2-15.

Table 4.2-1 (1) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electron Beam Method
1.	Process Description	Limestone ($CaCO_3$) is conveyed as slurry to absorber and sprayed into flue gas stream. Sulphur oxides (SOx) present in flue gas is absorbed as calcium sulfite ($CaSO_3$). Then, byproduct gypsum is produced by further oxidization and dewatering.	Limestone is conveyed as slurry to jet-bubbling reactor (JBR). Flue gas and air is injected into the JBR to form bubbling layer. Through the bubbling layer, SOx absorbing and oxidization are carried out. Then, byproduct gypsum is produced by dewatering.	In spray dryer method, slaked lime ($Ca(OH)_2$) slurry is atomized as fine droplets. The droplets are mixed with flue gas in a drying chamber, then the droplets are dried to powder and SOx is reacted with alkaline matter simultaneously. Powder is collected at the bottom of the spray dryer and at following dust collector.	Decarbonizing and a part of desulphurisation are carried out simultaneously by injection of $CaCO_3$ into boiler furnace. When absorber for water spray is installed at low flue gas temperature region after air preheated, SOx absorption reaction is further proceeded. Compound of $CaCO_3$ and Sulphur oxides forms dry powder, then collected and discharged at dust collector.	$Ca(OH)_2$ for desulphurisation is injected into duct at low flue gas temperature region after air preheated. When absorber for water spray is installed after $Ca(OH)_2$ injection, SOx absorption reaction is further proceeded. Compound of sulphur oxides forms dry powder, then collected and discharged at dust collector.	Flue gas pass through absorbent in gravity moving bed type absorber and SOx in flue gas absorbed in activated coke. Activated coke deteriorated in absorption performance is regenerated by heating in desorber. As by-product, sulphuric acid or elemental sulphur can be recovered.	Flue gas dusulfurisation is made by adding ammonia to flue gas and irradiating the flue gas with electron beams. Sulfur dioxide (SO_2) and nitrogen oxides (NOx) are oxidized into sulfuric acid (H_2SO_4) and nitric acid (HNO_3), respectively, by electron beam irradiation, the acids further turn to ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3) through neutralizing reactions with ammonia.

Table 4.2-1 (2) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

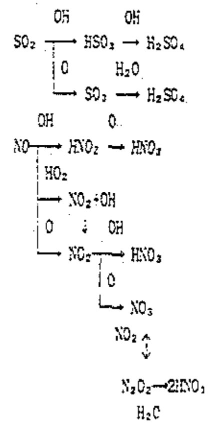
Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electron Beam Method
2.	Reaction Formula	(1) Absorbing Process $CaCO_3+SO_2+1/2H_2O \rightarrow CaSO_3 \cdot 1/2H_2O+CO_2$	(1) Absorption and Oxidation Process $SO_2+CaCO_3+\frac{1}{2}O_2+2H_2O \rightarrow CaSO_4 \cdot +2H_2O+CO_2$	(1) Absorption Process $Ca(OH)_2+SO_2+\frac{1}{2}H_2O \rightarrow CaSO_3 \cdot \frac{1}{2}H_2O+H_2O$	(1) Reaction in Furnace $CaCO_3 \rightarrow CaO+CO_2$ $CaO+SO_2+1/2O_2 \rightarrow CaSO_4$	(1) Reaction in Dust $Ca(OH)_2+SO_2 \rightarrow CaSO_3 \cdot 1/2H_2O+1/2H_2O$ $Ca(OH)_2+SO_2+1/2O_2+H_2O \rightarrow CaSO_4 \cdot 2H_2O$	(1) Absorption process $\frac{1}{2}O_2+[AC] \rightarrow Oad \cdot [AC]$ $SO_2+Oad \cdot [AC] \rightarrow SO_3ad \cdot [AC]$	(1) Oxidation process 
		(2) Oxidizing Process $CaSO_3 \cdot 1/2H_2O+1/2O_2+3/2H_2O \rightarrow CaSO_4 \cdot 2H_2O$		(2) Oxidation Process $CaSO_3 \cdot \frac{1}{2}H_2O+\frac{1}{2}O_2+1\frac{1}{2}H_2O \rightarrow CaSO_4 \cdot 2H_2O$	(2) Reaction in absorber $CaO+SO_2+1/2H_2O \rightarrow CaSO_3 \cdot 1/2H_2O$ $CaO+SO_2+1/2O_2+2H_2O \rightarrow CaSO_4 \cdot 2H_2O$ $SO_2+H_2O \rightarrow H_2SO_3$ $CaO+H_2SO_3 \rightarrow CaSO_3 \cdot 1/2H_2O+1/2H_2O$	(2) Reaction in absorber $SO_2+H_2O \rightarrow H_2SO_3$ $Ca(OH)_2+H_2SO_3 \rightarrow CaSO_3 \cdot 1/2H_2O+3/2H_2O$	(2) Desorption Process $SO_3ad \cdot [AC]+\frac{1}{2}C \rightarrow SO_2+\frac{1}{2}CO_2+[AC]$ (3) Byproduct Process The reaction formula is shown in the section of "Byproduct".	(2) Neutralization Process $H_2SO_4+2NH_3 \rightarrow (NH_4)_2SO_4$ $HNO_3+NH_3 \rightarrow NH_4NO_3$

Table 4.2-1 (3) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electron Beam Method
3.	SO_x Removal Efficiency	Approx. 90% DeSOx Eff. can be increased by increment of liquid and gas ratio (L/G). Cheeper limestone compared with other adsorbents can be used.	Approx. 90% Higher DeSOx Eff. can be obtained by increment of the sparger pipe submergence depth in the absorbent of the Jet Bubbling Reactor (JBR). Limestone can be used as absorbent.	Approx. 80 ~ 90% Up to around 1,000 ppm inlet SO_2, DeSOx Eff. can be the same as the Wet limestone-gypsum method. Slaked lime ($Ca(OH)_2$) is used as absorbent which has higher reaction characteristics and higher price.	Approx. 40 ~ 70% (In case of no water spray tower 30~40%) Higher DeSOx Eff. compared with other simplified DeSOx systems can be obtained. Limestone can be used because it is injected into high temperature furnace. However, twice as much of absorbent is required as Wet limestone-gypsum method.	Approx. 40 ~ 70% (In case of no water spray tower 30~40%) The same level of DeSOx Eff. as the absorbent injection into furnace can be performed. Absorbent is injected into duct with less temperature than furnace, therefore slaked lime of higher reaction rate is used.	Approx. 90% By the absorption function of activated coke, DeSOx Eff. can be as the same as Wet limestone-gypsum method. DeSOx Eff. differs according to space velocity (SV) and recirculation amount of activated coke.	Over 95% (DeNOx efficiency is about 80%.) The DeSOx efficiency depends on the flue gas temperature (Optimum at about 70°C), ammonia injection and electron beam absorption. The DeSOx efficiency rises as the flue gas temperature lowers. As for the relation between ammonia injection and DeSOx efficiency, the efficiency saturates when the SO_2 equivalence ratio of ammonia is 1.

Table 4.2-1 (4) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electron Beam Method
3.	SO_x Removal Efficiency				Water injection after the furnace is required to get better Eff. DeSOx Eff. relay on boiler load and flue gas tempera-ture. When no water injection by spray tower is performed, DeSOx Eff. is to be about 30~40%.	Water injection is required to get better Eff. DeSOx Eff. relay on boiler load and flue gas temperature. When no water in-jection by spray tower is performed, DeSOx Eff. is to be about 30~40%.	The smaller SV is the higher DeSOx Eff. Increment of activated carbon circulation amount makes higher DeSOx Eff., however, make up amount of activated cple is increased.	
4.	Dust Removal Efficiency	Approx. 90% Dust removal is performed by inertia impingement of dust with spray drops. Dust removal Eff. is determined by L/G, particle size, and spray drops size. High dust removal Eff. can be obtained.	Approx. 90% Dust removal is performed in JBR. High dust removal Eff. can be obtained by turbulent gas and liquid contact through JBR.	Approx. 90% (With dust collector) Dust collector installed after spray dryer performs dust removal. The system including dust collector offers the same level of dust removal as the wet type.	Approx. 90% (With dust collector) Dust removal is performed by dust collector installed after DeSOx reactor. The system including dust collector offers the same level of dust removal as the wet type.	Approx. 90% (With dust collector)	Approx. 90% Moving bed absorption tower has the function of dust removal. The faster cir-culating speed is the less dust removal Eff. Dust removal Eff. is the same level as the wet type.	Approx. 90% Dust is removed by a dust collector present downstream of the reactor. The dust removal efficiency of the whole system including the dust collector is as high as that in the wet limestone-gypsum method.
5.	Technical Maturity	It has been recognized as a proven technology for commercial use.	The same description as left.	It has been recognized as a proven technology for commercial use as the same as the wet type.	Tests in pilot plants and demonstration plants have been conducting. One commercial plant has been operating.		Tests in demonstration plants were finished and several commercial plants have been operating.	The method is at the stage of testing at demonstration plants.

Table 4.2-1 (5) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electron Beam Method
6.	(1) Operational experience in commercial plants	About 40% of DeSOx system in the world consists of Wet limestone-gypsum method. When share of another type of wet DeSOx system namely wet limestone-sludge disposal method is added, it would be over 50%.		Spray dryer system have been popular in Europe and the United States.	Share of this simplified DeSOx system which injects absorbent into furnace or duct is about a few percent in the world. Numbers of commercial plants with this system are limited and present (Apr. 1991) status of this system is that research and development are promoted by sponsors of industries and manufacturing firms in the United States, Canada, and Europe including EPRI, EPA, and DOE of the United States of America.		This system using activated coke were researched and developed as a simultaneous DeSOx-DeNOx in the later half of 1960's.	The method is attracting much attention for its advantages that the method allows to remove SOx and NOx at the same time and that the equipment is simple and easy to operate. The method, however, is currently at the stage of demonstration test without any experience of the use for commercial plants. The evaluation of ammonium sulfate and ammonium nitrate which are produced as byproducts in huge quantities varies depending on the country.
		At the present, wet spray tower DeSOx system is the most experi-enced system and it has been recognized as the most proven technology.	There is CT-121 model of JBR for commercial use. There are fifteen (15) commercial plants including one plant under construction.	This system has been evaluated as the same proven technology as the wet type.	Only one commercial plant which reports good operational experience is the one called LIFAC (Limestone Injection with an Activation Reactor) applied to the No. 4 unit (250MW) of Inkoo coal-fired power plant of IVO in Finland.		After that, demonstration tests at coal-fired power plants were carried out and now several commercial plants have been operating.	

Table 4.2-1 (6) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electron Beam Method
6.	(1) Operational experience in commercial plants	Latest model of in-situ oxidation single tower with 500MW equivalent capacity is in operation. As the latest model of this system, a single tower in situ forced oxidation DeSOx system for 1,000MW coal-fired plant was put into operation in June 1990. (2x500MW equivalent DeSOx system).	As a commercial plant for a coal-fired power plant, 2 units of 200MW soot-separation two-tower, DeSOx system has been operating since 1984. A pilot test of a soot-mixed, single-tower improved CT-121 with 1,500 m^3N/h flue gas volume was finished in 1988. At the present, this system for 700MW coal-fired power plant is under construction (as of April, 1991).	The reason why spray dryer method has not been applied so widely as the wet type is that disposal problem with by-product and higher running cost with expensive slaked lime consumption.	Research and development history of No. 4 unit of Inkoo power plant are as follows: a. Full scale lime injection and half scale activation reactor to the flue gas volume of No.4 unit were installed as research purpose which put into operation in January, 1986. b. The other half scale of activation reactor was installed as a commercial plant and renovation of the limestone injection system was carried out and the system was pout into operation in January, 1988. c. The activation reactor installed research purpose was replaced with new one that is the same model as the one installed as commercial plant and the system was put into operation in January 1990. It is generally said that this system is suitable for a plant which is not required high DeSOx Eff. as it is the simplified DeSOx system.		Numbers of commercial plants are limited and there is no experience in a large scale coal-fired power plant.	

Table 4.2-1 (7) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
6.	(2) Operational experience in commercial coal-fired plants	193 Plants* There are over 193 applications to coal-fired power plants. Many plants including big scale plants of 350MW, 500MW and 700MW class for coal-fired power plants have been installed and in operation.	25 Plants As of July 1992, there are 25 applications to coal-fired power plants. As the biggest plants in operation, there are two 350MW plants. At the present, 700MW equivalent plant is being constructed and will be in operation in 1993.	87 Plants* There are 87 applications including big scale plants of 350MW and 500MW class to coal-fired power plants. Application of the spray dryer system is popular especially in Europe and the United States of America.	1 Plant There is one 265MW equivalent commercial plant for a coal-fired power plant.	25 Plant* The biggest scale in a coal-fired power plant is 350MW equivalent.	3 Plants There are 3 applications to coal-fired power plants. The biggest application of 130MW equivalent plant is under operation. A plant for a 350MW fludized bed combustion boiler is under planning which is scheduled to be in operation in July 1995.	• None* The method is still at the stage of pilot test and demonstration test, and it has not been applied to a coal fired power plant yet. The method is being tested at the maximum gas volume of 24,000 m^3/h.

* Figures in IEA Coal Research, "FGD installations on coal-fired plants" published by IEA in April 1990 (including under construction units as of April 1990).

Table 4.2-1 (8) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
7.	Reliability	Measures for corrosion and erosion with DeSOx and dust removal of flue gas and with handling of absorbent and by-product gypsum are required. Measure for scaling in the absorbing tower is required.		Major problems with this system are erosion and plugging of absorbent atomizer installed in the absorber.	Simplified DeSOx process by absorbent injection has limited application to commercial plants and operational experi-ence of commercial plants are short, therefore the reliability on long term operation of this system will be proved by the further experience in the future.		Several com-mercial DeSOx plants with this method have been operating but there is no big scale application to coal-fired power plant, more over, operation experiences of commercial plants are rather short (as of Apr. 1991). In processes of recovering elemental sulphur or sulphuric acid as by-product, there are many chemical reaction processes which makes complicated equipment arrangement, therefore maintenance and by-product recovering system is more complicated than the wet type.	The method must be tested for equipment reliability at continuous operation and plant economy before the method is utilized at commercial plants. It is judged therefore that the reliability of the method is lower at present than that of the wet limestone-gypsum method or spray-dryer method.

Table 4.2-1 (9) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
7.	Reliability	This system has enough reliability for the above problems because a lot of renovation were carried out in design, structure, material of each part of system during the long history from the development stage to the present. Maintenance carried out at a periodical inspection of a power generation plant has proved continuous operation without problem for one year.	As the operation results of the soot separation CT-121 (200MW) and the good test results of the soot mixing CT-121 (1,500 m^3N/h), it is believed that the reliability would be comparative to the spray tower method. An operational experience with a big scale of this system will be given by 700 MW equivalent DeSOx system which is under construction (as of Apr. 1991).	There are two types of atomizing method, one is rotary atomizer and the other one is two-fluid nozzle. Rotary atomizer is usually adopted to more than 250MW class boilers as the atomizer gives good atomizing efficiency hence residence time in the absorber can be shortened and less nozzle plugging than the two-fluid nozzle. Rotary atomizer rotates at about 11,000 rpm, therefore periodical inspection and adjustment for atomizing nozzles and cleaning of scale at rotary desk are required.	As weak points of this system, followings can be considered. a. low DeSOx efficiency b. Influence to fouling and slugging of boiler furnace c. Unknown factors when it is scaled up to large scale plant d. Increase of dust lead to existing ESP (in case of existing ESP is used as dust collector for DeSOx system) There are still some items to be proved like the above, therefore the reliability of this system at the present is far less than the wet type or the spray dryer processes.			

Table 4.2-1 (10) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
7.	Reliability			In case of rotary atomizing nozzles, inspection and adjustment in every three-month and replacement in every year are required. This system is simple because which has less interiors in the absorber than the wet type and has no big size pumps like slurry circulation pumps in the wet spray tower method. Therefore, when the spray dryer DeSOx system has one stand-by atomizer, it gives the same level of reliability as the wet type.			Therefore, reliability of this system on long term continuous operation of 500MW class at the present is less than the wet type and the spray dryer.	

Table 4.2-1 (11) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
8.	By-product (1) Kinds of by-product	Gypsum ($CaSO_4 \cdot 2H_2O$)		Compound of flyash and re-action product (Flyash+$CaSO_3$+ $CaSO_4$+$Ca(OH)_2$)	Compound of flyash and reaction product (Flyash +$CaSO_3$ + $CaSO_4$ + $Ca(OH)_2$)		Elemental sulphur or sulphuric acid (H_2SO_4 or S)	Ammonium sulfate ($(NH_4)_2SO_4$) Ammonium nitrate (NH_4NO_3) Both ammonium sulfate and ammonium nitrate are effective fertilizers, and they have commercial values. They, however, are produced in huge quantities, and they will have much effects on fertilizer market of the country.

Table 4.2-1 (12) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item	Wet Type		Semi-Dry Type			Dry Type	
	Limestone-Gypsum Process						
	(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
(2) Disposal of by-product	High quality of gypsum is re-covered as by-product and it can be used as cement raw material and gypsum wall board. In the United States, non-recovering of by-product is rather popular because there are many places for land reclaiming, cost reduction of DeSOx system can be achieved without by-product recovering system and a lot amount of by-product is recovered with high sulphur coal. Countries other than the Unite States, by-product has been recovered as commercial gypsum, because there are limited areas for disposal and land re-clamation, and gypsum has value for commercial use.		By-product from the spray dryer system which is compound of flyash and reaction product can be handled with usual ash handling system because physical characteristics of the by-product is dry small particles that has fluidity very like flyash. Research and development of effective use of by-product are under way.	By-product of this system has similar characteristics as the spray dryer method since the reaction mechanism of the system is close to the spray dryer system, therefore disposal of by-product is nearly the same as the by-product of the spray dryer process. According to the test results report from No. 4 unit of Inkoo power plant of IVO in Finland, by-product of LIFAC has stability and self hardening characteristics, therefore there is a possibility to use it as road bed material and construction material.		SO_2-rich gas (SO_2 concentration 20 to 25 vol.%) produced by heating of SO_2 adsorbed activated coke carbon at desorber is sent to by-product recovery system to recover the by-product. As by-product, elemental sulphur or sulphuric acid can be selected. Process of each case is as follows. a. Sulphuric acid recovery After dust and impurities are removed from the SO_2-rich gas, the gas is oxidized in a converter to form SO_3. The SO_3 is then absorbed in an absorber to form sulphuric acid.	

Table 4.2-1 (13) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
8.							$SO_2+\frac{1}{2}O_2 \rightarrow SO_3$ $SO_3+H_2O \rightarrow H_2SO_4$ b. Elemental sulphur recovery SO_2-rich gas is reduced to H_2S in a reduction claus using a carbon-bonaceous reduction agent. H_2S and SO_2 is converted to elemental sulphur in a claus unit. $C+SO_2 \rightarrow S+SO_2$ $C+CO_2 \rightarrow 2CO$ $C+H_2O \rightarrow CO+H_2$ $H_2+S \rightarrow H_2S$ $CO+S \rightarrow COS$ $COS+H_2O \rightarrow H_2S+CO_2$ $H_2S+\frac{1}{2}SO_2 \rightarrow 1\frac{1}{2}S+H_2O$ The carbonyl sulphide (COS) which is generated secondarily in the reduction column, is hydrolyzed in the claus unit and eventually elemental sulphur is obtained.	

Table 4.2-1 (14) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process		(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
		(1) Spray Tower Method	(2) Jet-Bubbling Method					
9.	Utilities (1) Absorbent	Limestone $CaCO_3$ Limestone which is lower price is used as absorbent. Usually, lime-stone is procured as powder phase, and it is used as a slurry phase. Usually, limestone powder passed the 325 mesh is more than 95%.		Slaked Lime $Ca(OH)_2$ Slaked lime is used as absorbent which has higher re-action characteristics than limestone.	Limestone $CaCO_3$ Limestone can be used as absorbent.	Slaked Lime $Ca(OH)_2$ Slaked lime is used as absorbent in order to obtain higher reaction rate.	Activated Coke Expensive activated coke is used as absorbent.	Ammonia (NH_3) (Neutralizer) No absorbent is required because reactions are caused by electron beam, but ammonia is used as a neutralizer for generation of byproducts.
		Density of limestone slurry which is sprayed into the absorber is about 15%. In case of insitu forced oxidation (IFO), the system can be designed with excess feeding ratio of absorbent at about 1.02. (In case of applying separate oxidation tower, it would be about 1.05.)	Density of limestone feeding to absorber is about 25%. Density of limestone in mother liquid of absorber is less than 0.2%. The system can be designed with excess feeding ratio of absorbent at about 1.01 which is less than spray tower method.	Usually, powdered quick lime (*CaO*) or slaked lime $Ca(OH)_2$ is received as absorbent material. CaO or $Ca(OH)_2$ is slaked by slaking system and used as slurry phase. Slaking is carried out with water and with heating at about 80°C in order to get buter slaking reaction.	In order to obtain 70% *DeSOx* Eff., this system needs about twice as much limestone as the wet type.	In order to get 70% *DeSOx* Eff., this system needs quantity of slaked lime as the same as Spray Dryer Method with 90% Eff.	Activated coke that loss SOx absorbing ability is regenerated by regenerator continuously. Activated coke as chemical-loss at a process of reaction and powdered-loss at a process of drying re-generation. Usually, make up of activated coke is 1.5% per quantity of circulation at moving bed absorption tower.	

Table 4.2-1 (15) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
9.	(1) Absorbent			In order to get the same level of DeSOx efficiency as wet limestone/ gypsum method (Approx. 90%), it is necessary to feed absorbent with excess feeding ratio of about 1.3~1.5, therefore a lot amount of more expensive absorbent than limestone is required.				
	(2) Water	Following make up water is required. a. Evaporating water at absorption tower. b. Surface moisture of by-produced gypsum c. Crystallization water of by-produced gypsum d. Blow off water to control liquid quality in the system. Waste water discharged from gypsum recovering process can be recycled as dissolving water of absorbent and etc.		Spray Dryer Method needs a lot of water as the same as the Wet Type Method because almost all of droplet of absorbent-slurry sprayed to spray dryer evaporate and goes out through stack.	Since almost all of water sprayed to absorber evaporate and goes out through stack, this method needs a lot of water as the same as the Wet Type Method.		In by-product recovering process, cooling water is required for desorption gas cooling.	Cooling water is required because the flue gas must be cooled before it gets in the reactor.

Table 4.2-1 (16) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
9.	(3) Steam	When flue gas after FGD is reheated by Gas/Gas heater (GGH), steam for soot blowing is required. In case of other reheating equipment are used, following steam is required. a. After-burner type • atomizing steam b. Steam heater type • heating steam		Steam is required for absorbent slurry in a slaking system. Steam for flue gas reheating is not necessary, because flue gas is kept under dry condition. In order to protect visible white plume from a stack, sometime flue gas reheating system is adopted.	Steam for reheating equipment is not necessary for the same reason as Spray Dryer Method.		Flue gas reheating is not required, because of its process, flue gas temperature is not lowered.	The flue gas temperature does not go down in the process, and no reheating of flue gas is required. steam, however, is required for vaporizing the liquid ammonia.
9.	(4) Electricity	Spray Tower Method needs power for boost up fan and absorbent-slurry circulating pump as major consumer. This system consume more power than other systems because of power consumption of above equipments.	Jet-Bubbling Method doesn't need absorbent-slurry cir-culating pump. Draft loss of JBR is larger than spray tower method. Therefore, power consumption of boost up fan is larger than spray tower method. Total power consumption is less than the spray tower method.	Power consumption of Spray Dryer Method is about 70% of Wet Type. Because spray dryer has a few internal equip-ment and this method doesn't have large size equipment like slurry cir-culating pumps.	These systems are simplified and less auxiliary equipped systems compared with others, therefore power consumption of these systems are about 18 to 20 % of the spray tower method.		Power consumption is about 30% of Wet Type Method, because absorber is moving bed type and this method requires no large size equipment.	Much electricity is required, in comparison with other method, for electron beam generation.

Table 4.2-1 (17) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
	(5) Others	In case of insulation of waste water treatment system, chemical is needed. When flue gas is heated up by after burner not GGH, fuel for after burner is required.					Deteriorated activated coke is regenerated at regeneration tower continuously, fuel for heating for this regeneration process is required.	
10.	Waste Water	Limestone-Gypsum Method usually produce waste water in by-product recovering process. Quantity of waste water depends on reacted slurry amount extracted from absorber. Quantity of bleeding of reacted slurry is controlled so as to settle the density of chlorine which affect the DeSOx efficiency and the corrosion resistibility of the desulphurisation system. Waste water contains dust, volatile matters such as fluorine, chlorine and COD which is produced in gypsum formation process.		No waste water is generated because water in injected absorbent slurry is evaporated and then the reacted product is exhausted in the form of dried particles.	No waste water is generated because the reacted product is exhausted in the form of dried particles as the same as the spray dryer method.		No waste water is generated in the process of absorbing because the system is dry moving bed type, however the by-product recovering process generate waste water.	No waste water results. All water sprayed to flue gas evaporates, and reaction products are obtained in the form of dry powder.

Table 4.2-1 (18) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
11.	Stack Lining and Treated Gas Reheating	The treated gas after absorber is moisture saturated gas with the temperature of approx. 50°C and contains a small amount of mist. Therefore, when the gas is exhausted to the stack without any appropriate countermeasures, it will condensate in the stack and will cause corrosion, furthermore the moisture saturated gas with mist will be exhausted from the stack with high speed, as a consequence the mist will be separated in the atmosphere and will fall in the vicinity of the stack. The Mist will corrode the outer wall of the stack and auxiliary machines nearby due to its strong acid (pH ≒ 2). Therefore, anti-corrosion lining to absorber outlet ducts and stack and reheating of the treated gas up to 80°C to protect stack lining and to prevent the fall of the mist to the surroundings are necessary.		The flue gas and reacted product are completely dried because the gas temperature at the spray dryer exit is kept 10~20°C higher than the dew point. SO_3 is removed by the chemical reaction which is per-formed inside the spray dryer. From above reasons, lining work for the ducts and the stack to protect from the cor-rosion by the sulphuric acid mist is un-necessary and flue gas re-heating is also unnecessary.	It is said that the lining work for ducts and stack is unnecessary because the same chemical reaction is performed as the same as spray dryer system. Flue gas reheating is also unnecessary because the system is dry type. However, Unit No. 4 of Inkoo Power Station in Finland which adopts LIFAC System has a steam gas heater downstream the absorber to reheat the flue gas up to 75°C in order to protect the ESP and the stack from corrosion which would be able to occur since the system applies water spray tower to get better DeSOx Eff.		The lining work for the ducts and the stack and the flew gas reheating are unnecessary because there is no temperature drop in the system.	Duct or stack lining is not required as in the case of the spray-dryer method. In addition, no reheating of the gas is required because of the process.

Table 4.2-1 (19) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

Item		Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
12.	Operational Characteristics (1) Load Change Characteristics	The system responds well to normal load change of boiler maintaining designed DeSOx efficiency. Time constant of DeSOx performance of absorbent slurry to inlet SOx amount is large, therefore the system can follow load change at step like.		For normal load change of boiler, the system offer the same level of load response as the wet lime-stone-gypsum method, however there is a limitation on lowest temperature of SDA inlet flue gas temperature at which the system can be put into operation (or absorbent injection) in order to keep SDA outlet temperature well above the saturate temperature of flue gas. Late absorbent injection at plant start up and early stop of the injection at plant shut down are required for the reason of the above.	The system responds to boiler load by controlling absorbent feed rate into the furnace or flue gas duct and water spray flow rate into the reactor when water spray tower is applied. SO_2 removal ratio depends much on gas temperature of the absorbent injection area and/or the reactor and is very sensitive to these gas temperature. SO_2 removal efficiency changes by the boiler load and the flue gas temperature. Therefore, these system suit for a continuous load operation plant with a constant load, but not good for a plant which will be operated frequent load increase/decrease or start-up/shut-down.		The same description as Limestone-Gypsum Method.	As in the case of the activated coke method, DeSOx by this method easily follows the boiler load while maintaining the DeSOx efficiency. Both ammonia injection and electron beam absorption rapidly follow changes in the inlet SOx concentration.

Table 4.2-1 (20) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
12.	Operational Characteristics (1) Load Change Characteristics			Therefore, DeSOx performance cannot be per-formed during these periods which may result in temporary over emission on regulated figure when it is regulated-based on concentration of SOx in flue gas.				
	(2) Operability	The system is simple with not many components in each process, therefore the operation is easy. Almost immediately after the FGD operation, flue gas can be introduced to the system.		In normal load operation, the operability is nearly the same as the limestone-gypsum method. But, in starting-up/shutting-down operation, it is severe due to limitation on the spray dryer outlet gas temperature.	It is required some effort to find out the most suitable control conditions such as absorbent injection flow rate, water spray flow rate into the reactor and reactor outlet gas temperature control in several operation conditions, since the SO_2 removal efficiency changes by the boiler load and the flue gas temperature. The system can be influenced sensitively to load change and operation conditions such as in-service burner stage, type of coal, etc.		The operation on absorbing process and draft system is easy and immediately after the FGD operation, flue gas can be introduced to the system. But, the operability on by-product recovery process and regeneration of activated coke process are worse than that of limestone-gpysum method, because this process is composed with many equipments and about 20 hours are required to warm up these processes.	Operations of the gas system and absorption system are easy. It is possible to pass gas as soon as the start of operation, but it would be difficult to control the flue gas temperature (70±3°C).

Table 4.2-1 (21) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

No.	Item	Wet Type: Limestone-Gypsum Process: (1) Spray Tower Method	Wet Type: Limestone-Gypsum Process: (2) Jet-Bubbling Method	Semi-Dry Type: (3) Spray Dryer Method	Semi-Dry Type: (4) Limestone Injection into Furnace Method	Semi-Dry Type: (5) Slaked Lime Injection into Duct Method	Dry Type: (6) Activated Coke Method	Dry Type: (7) Electro Beam Method
13.	Maintenability	It is necessary to take measures to prevent corrosion and abrasion due to SO_2 and dust removal of flue gas and handling of absorbent or by-product. Anticorrosion and antiabrasion materials are selected in accordance with the property of process liquid and/or chemical. For towers and basins resin lining is applied, for pipes rubber lining, etc. and for pumps in slurry process anticorrosion stainless materials or rubber lining, etc. are used. But, it is necessary to repair these materials because it is impossible to secure the perfect anticorrosion and/or antiabrasion materials. Further, the cleaning of towers, basins and pipes in the absorbent slurry process and gypsum slurry process are necessary to eliminate scale coating.		For major parts of spray dryer, ordinary mild steel can be used and no lining is necessary. Major problems in maintenance of this system are abrasion and clogging of spray nozzle of rotary atomizers. Rotary disk which is rotating at about 11,000 r.p.m. are equipped to the rotary atomizer. In order to overcome this abrasion problem, cleaning, inspection and adjustment of nozzles in every three months and replacement of nozzles in every year are necessary.	The maintenance is easy than that of limestone-gypsum method and spray dryer method due to simple system. It is necessary to pay attention regarding an abrasion and/or clogging of the spray nozzles.		Dry type absorber is employed for these system, therefore ordinal mild steel can be used and no lining for corrosion protection is required. In a process which produces sulphur or sulphuric acid as a by-product, the system configuration is complicated and special materials considering chemicals are used. Therefore, the maintainability is worse than that of lime-stone-gypsum method.	System maintenance is easy, in comparison with other methods, because the system is simple. The electron beam generator, however, is inferior in long-term stability.

Table 4.2-1 (22) Comparison of Various Flue Gas Desulphurisation System (1 Unit Base)

	Item	Wet Type		Semi-Dry Type			Dry Type	
		Limestone-Gypsum Process						
		(1) Spray Tower Method	(2) Jet-Bubbling Method	(3) Spray Dryer Method	(4) Limestone Injection into Furnace Method	(5) Slaked Lime Injection into Duct Method	(6) Activated Coke Method	(7) Electro Beam Method
13.	Maintenability			In comparison with wet lime-stone-gypsum method, this system has less interiors in SDA and there is no big size pumps like in wet limestone-gypsum method which makes equipment composition simple, therefore maintenability is better than that of wet limestone gypsum method.				
14.	Others			At the present, 14 meters in diameter SDA standard module is used for 200 to 500MW class commercial power plants. For large amount of flue gas treatment, numbers of module are increased. When it comes to 500MW power plant, number of module would be three.	When water spray tower after absorbent injection is applied, a diameter of the tower would be about 10 meters for 200MW class power plant. Area of 12 meters in diameter is required considering attached auxiliaries and maintenance space, etc.			

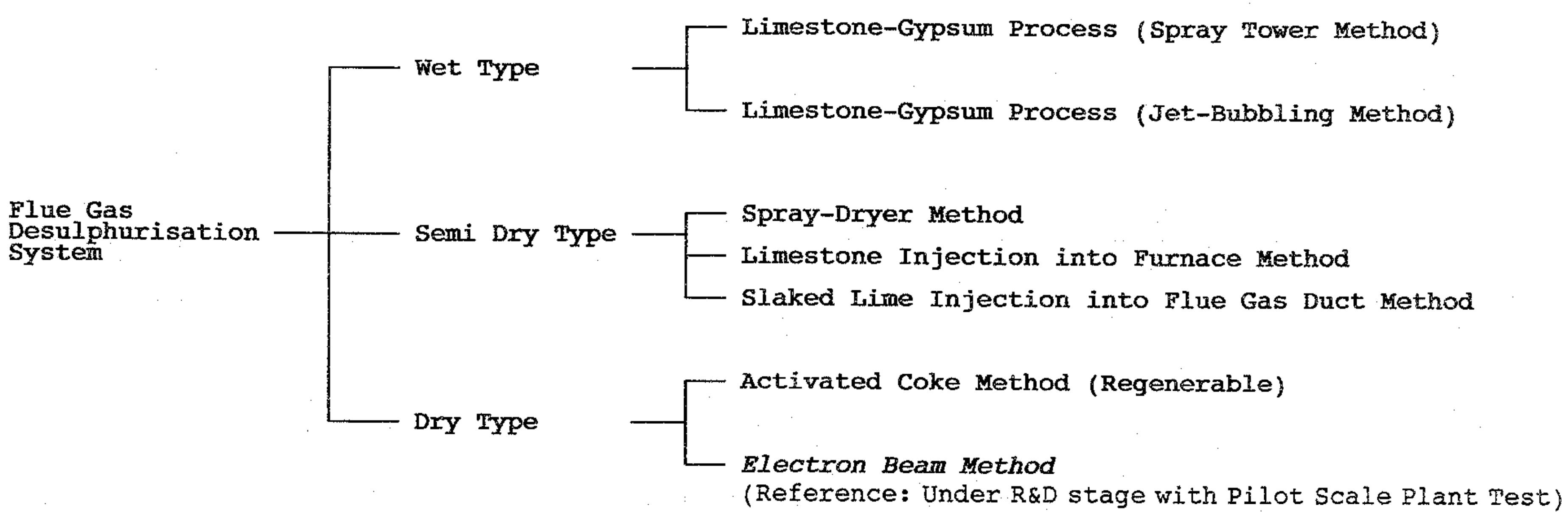


Fig. 4.2-1 FLUE GAS DESULPHURISATION SYSTEM

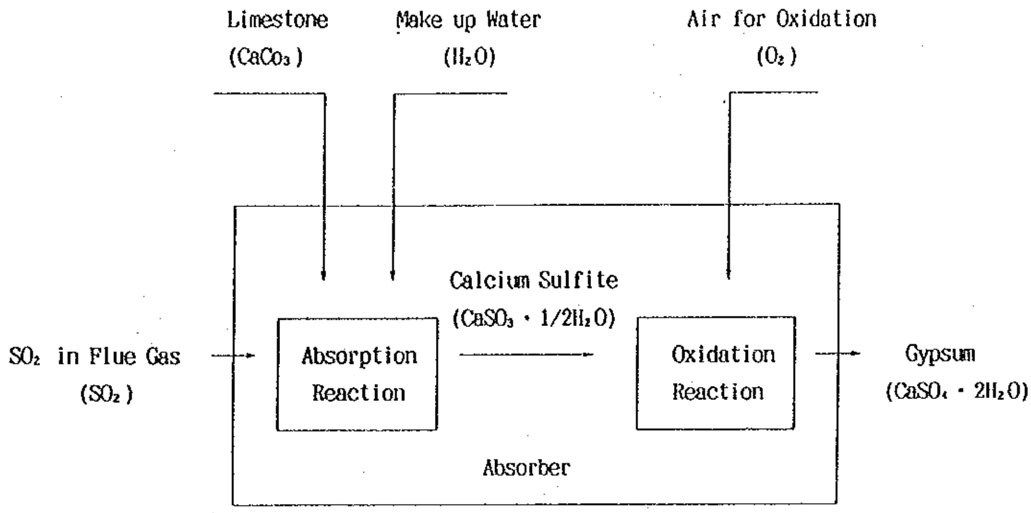


Fig. 4.2-2 REACTION FLOW OF WET LIMESTONE-GYPSUM PROCESS (SPRAY TOWER METHOD)

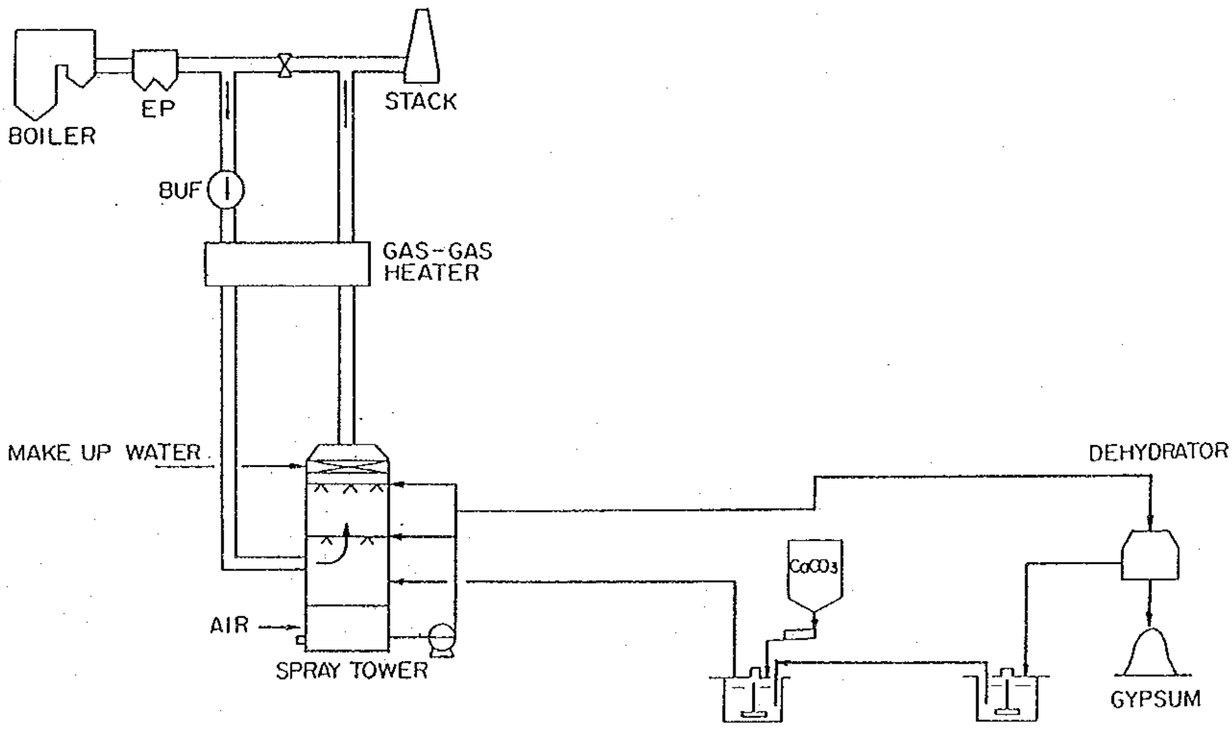


Fig. 4.2-3 PROCESS FLOW OF WET LIMESTONE-GYPSUM PROCESS (SPRAY TOWER METHOD)

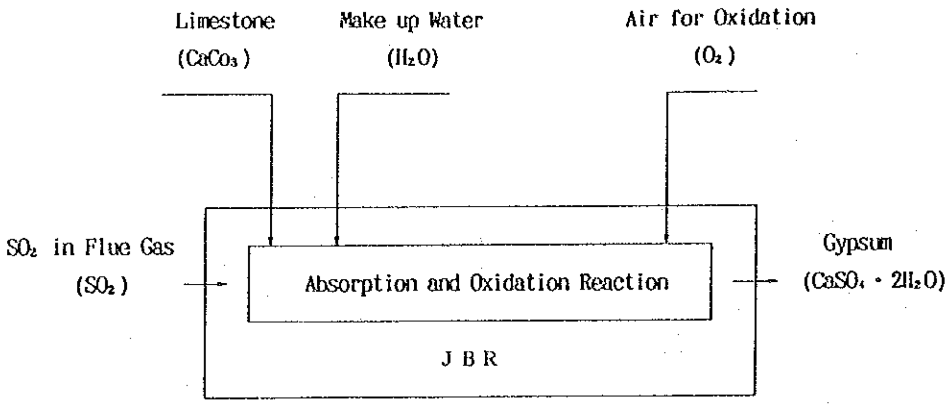


Fig. 4.2-4 REACTION FLOW OF WET LIMESTONE-GYPSUM PROCESS
(JET-BUBBLING METHOD)

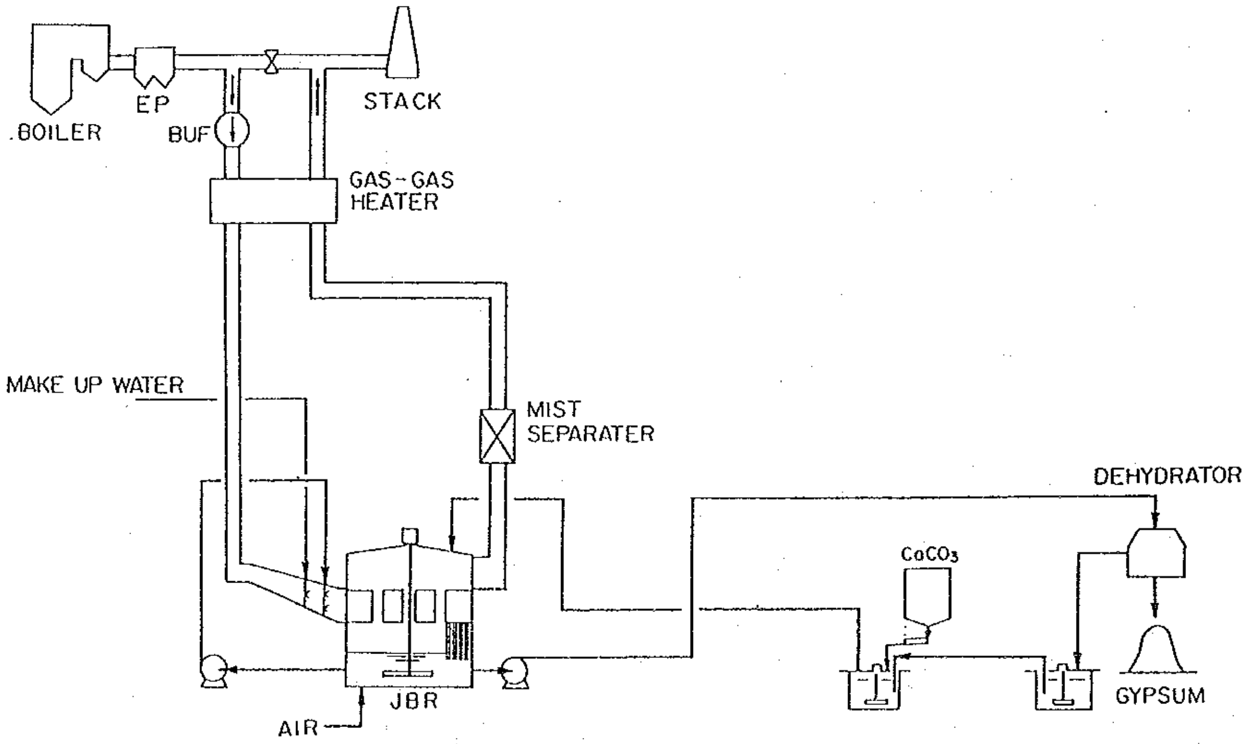


Fig.4.2-5 PROCESS FLOW OF WET LIMESTONE-GYPSUM PROCESS
(JET-BUBBLING METHOD)

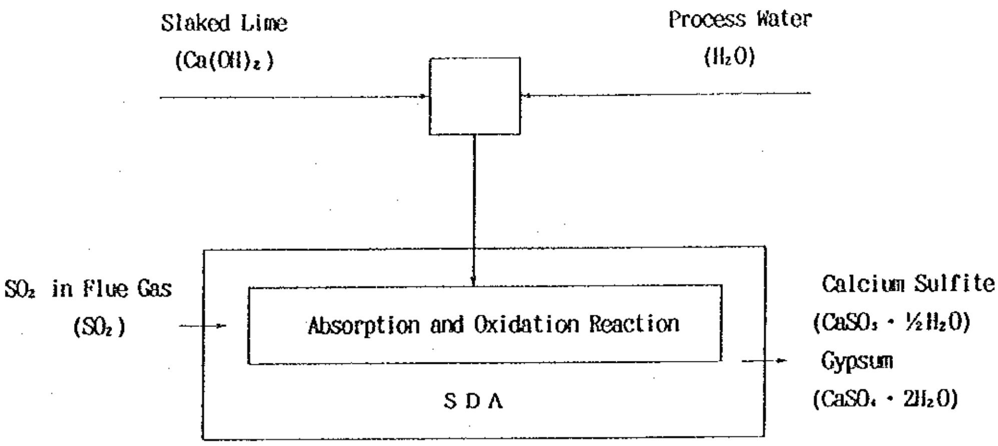


Fig. 4.2-6 REACTION FLOW OF SPRAY DRYER METHOD

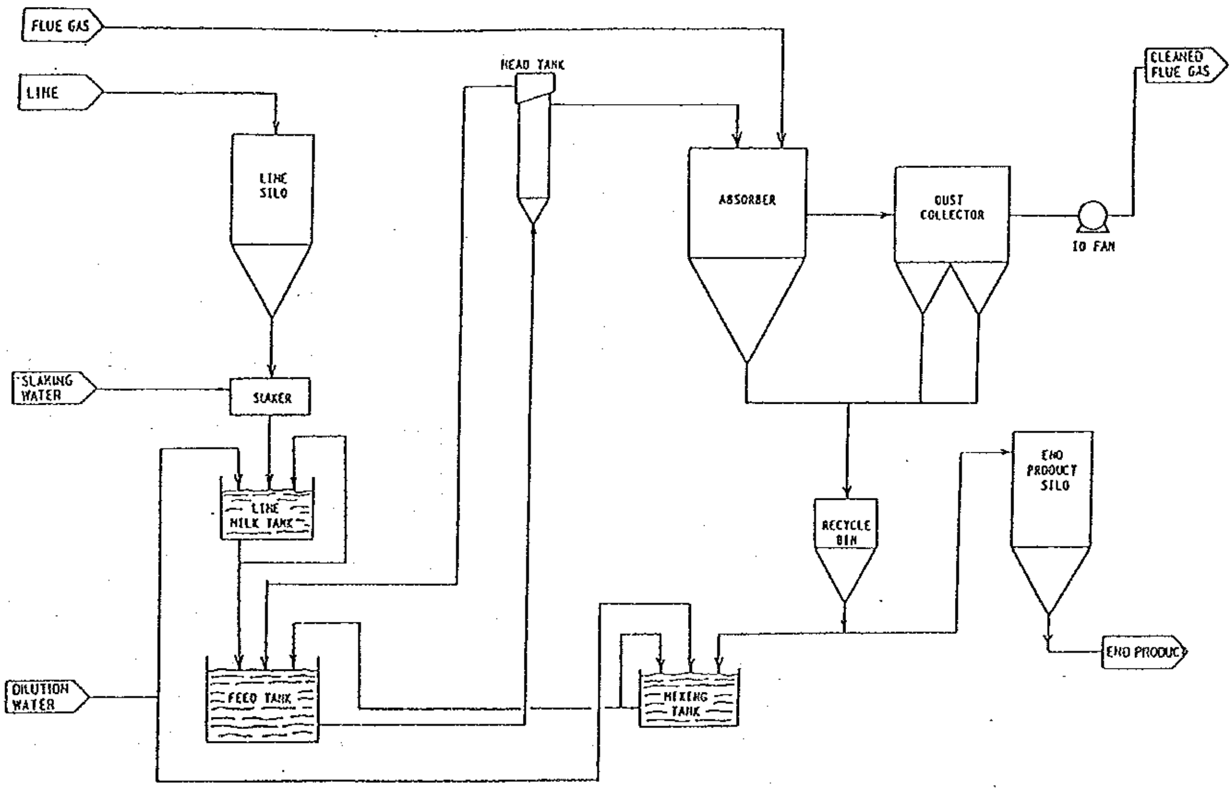


Fig. 4.2-7 PROCESS FLOW OF SPRAY DRYER METHOD

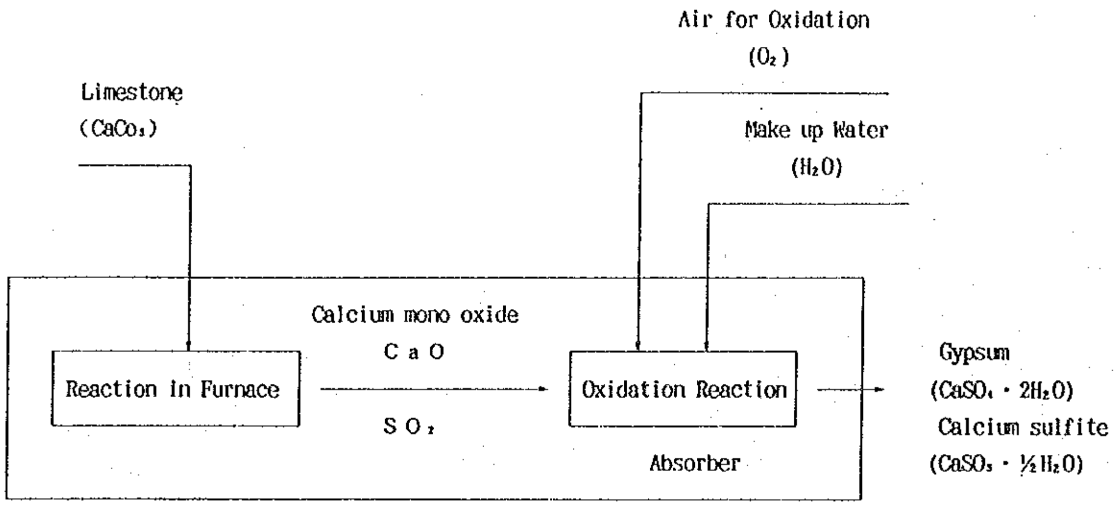


Fig. 4.2-8 REACTION FLOW OF DRY ABSORBENT FURNACE INJECTION SYSTEM

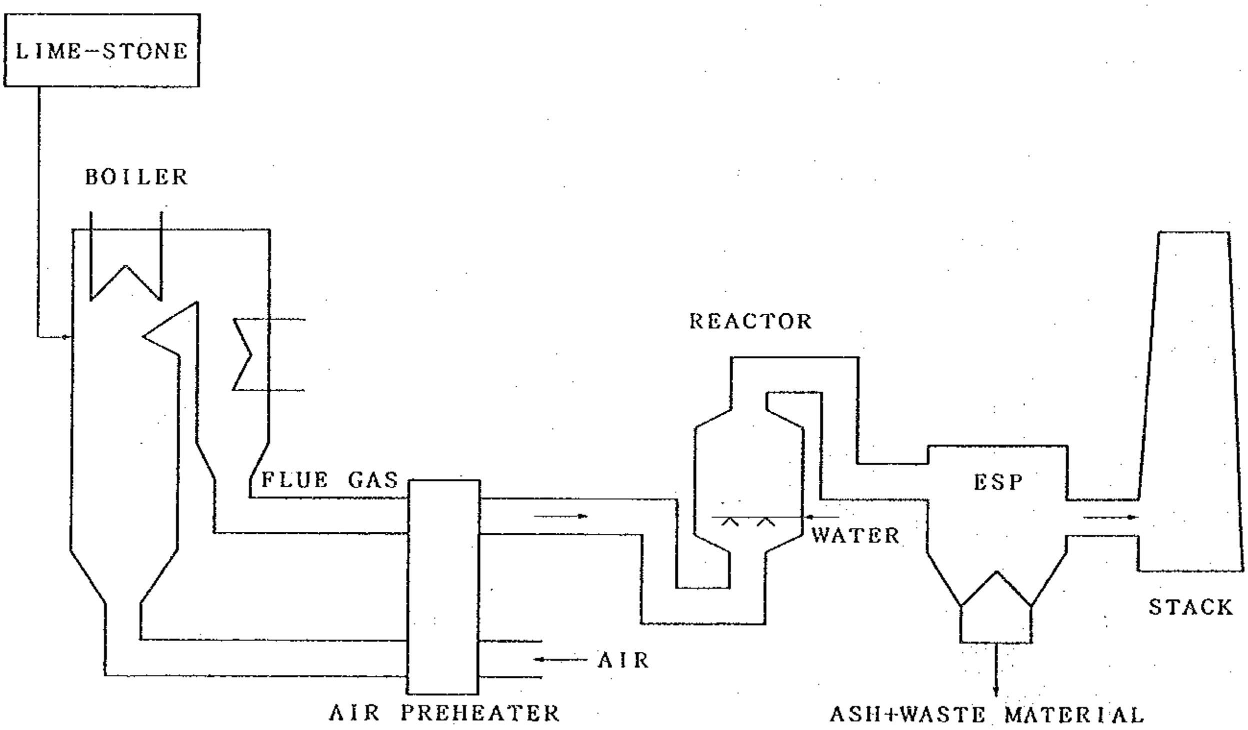


Fig. 4.2-9 PROCESS FLOW OF DRY ABSORBENT FURNACE INJECTION SYSTEM

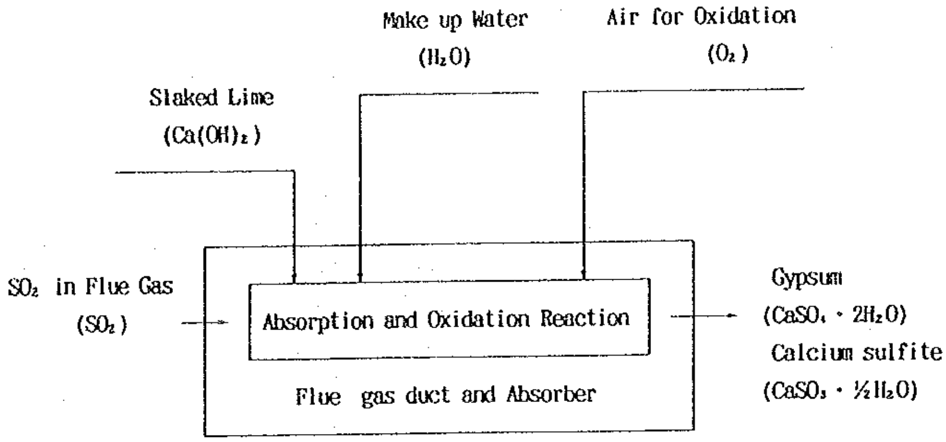


Fig. 4.2-10 REACTION FLOW OF DRY ABSORBENT DUCT INJECTION SYSTEM

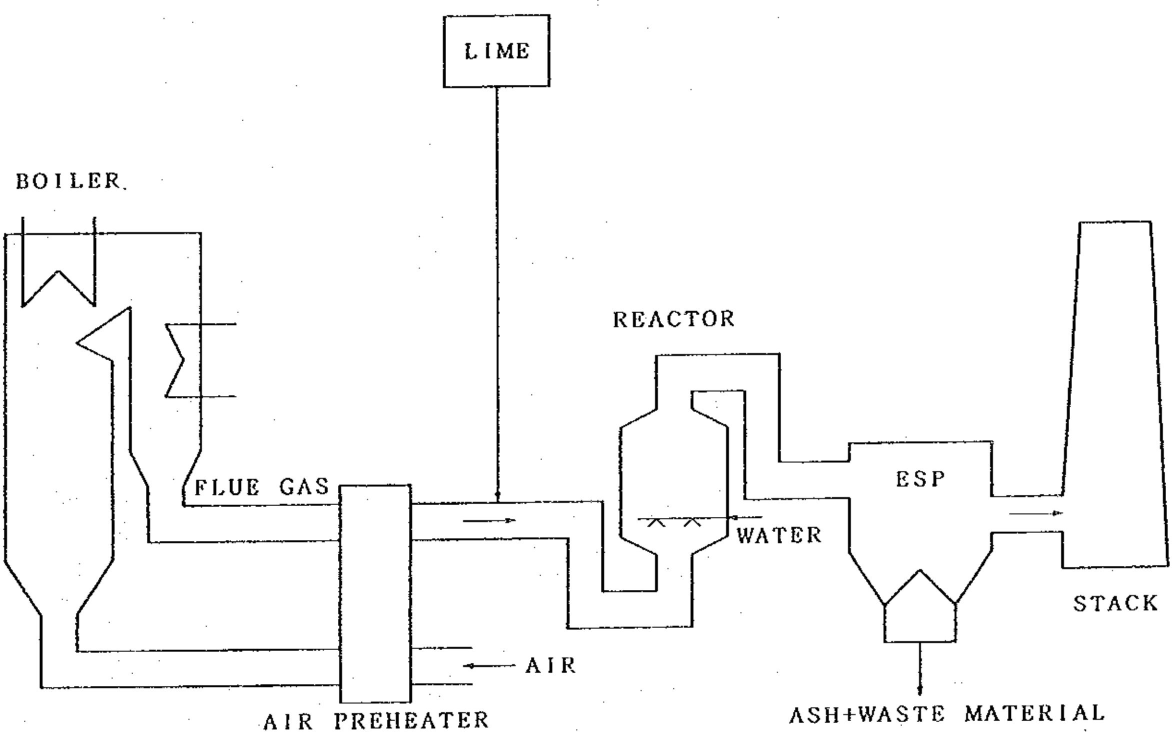


Fig.4.2-11 PROCESS FLOW OF DRY ABSORBENT DUCT INJECTION SYSTEM

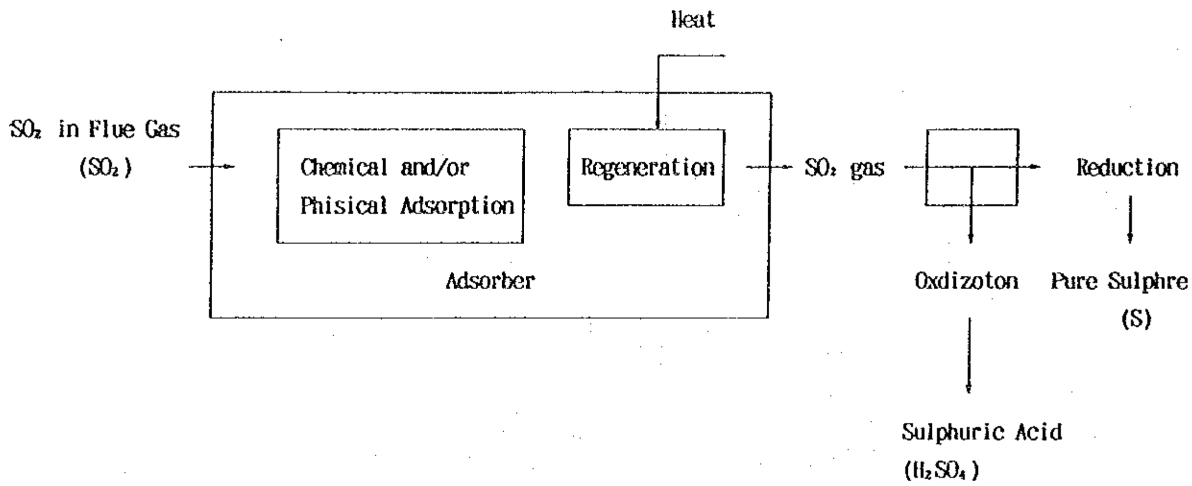


Fig. 4.2-12 ADSORPTION AND REGENERATION FLOW OF ACTIVATED COKE METHOD

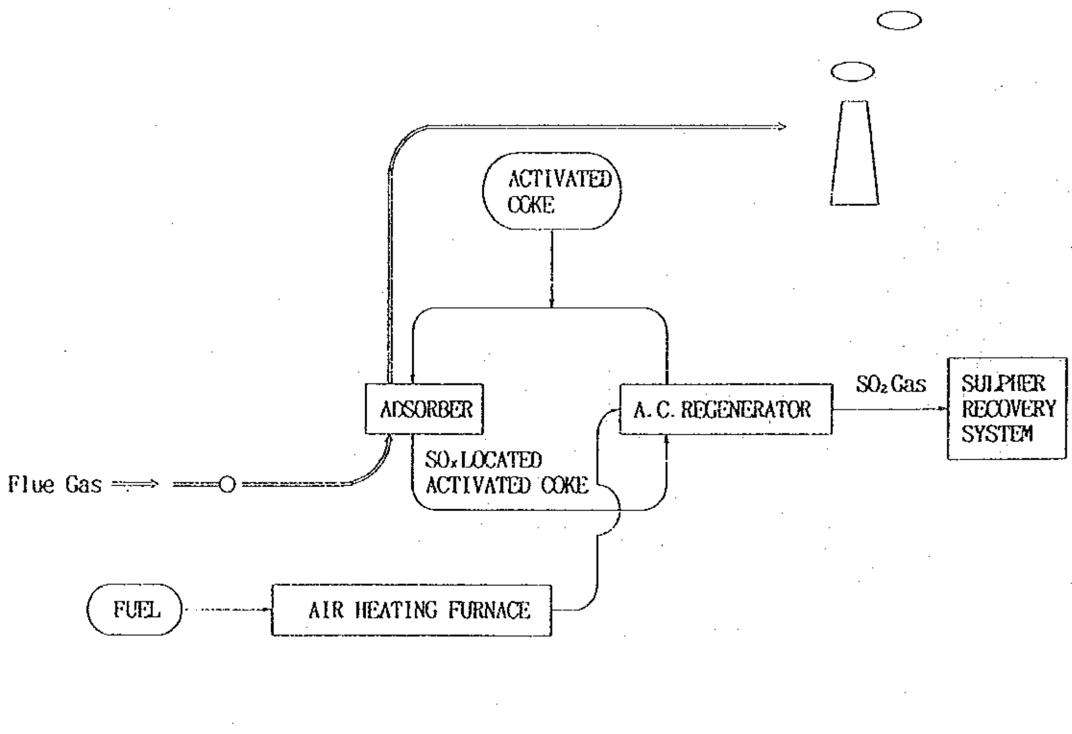


Fig. 4.2-13 PROCESS FLOW OF ACTIVATED COKE METHOD

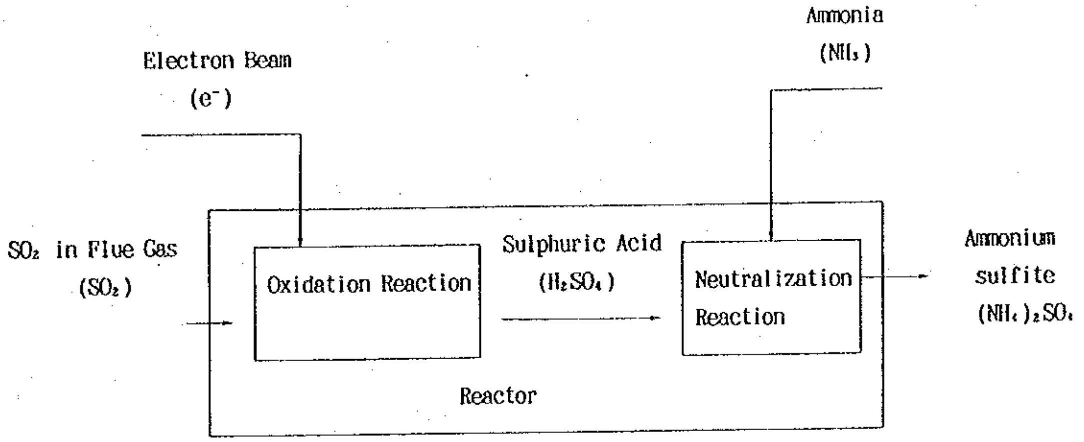


Fig. 4.2-14 REACTION FLOW OF ELECTRON BEAM SYSTEM WITH AMMONIA

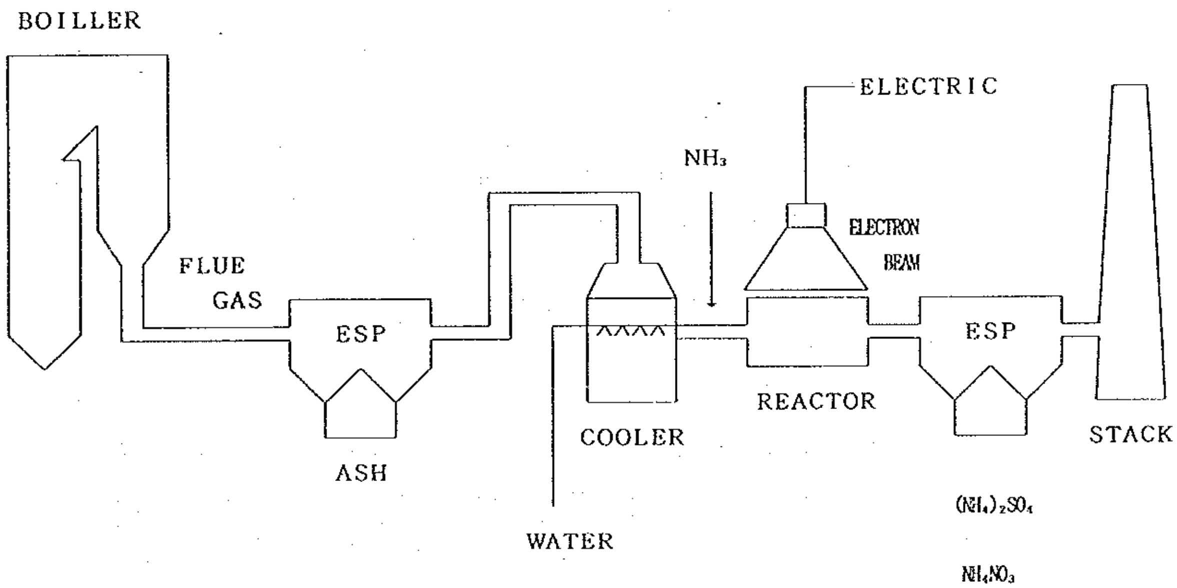


Fig. 4.2-15 PROCESS FLOW OF ELECTRON BEAM SYSTEM WITH AMMONIA

4.3 Study Conditions of the Optimum FGD Selection

To fulfill the deSOx efficiencies stipulated by legal regulation for the Melnik Power Station by employing some of the seven FGD methods described in Section 4.2, it is necessary to study the FGD methods for selection of some methods most pertinent to respective plants of Part II and Part III taking into account the conditions specific to the Melnik Power Station.

This section determines operating conditions specific to the Melnik Power Station for the purposes of studying the installation method (i.e. combination) of FGDs and selecting an optimum FGD method for Part II and selecting an optimum FGD method for Part III respectively.

It should be noted that operating conditions given below were determined based on the data and information obtained at meetings and surveys in the 1st and the second stages survey on FGD study for the Melnik Power Station conducted in Czechoslovakia.

4.3.1 Operating Conditions of Power Plants

(1) Capacity Factor

Part II: 58% (corresponding to annual operation of 5,081 hours at the rated load)

Part III: 51% (corresponding to annual operation of 4,468 hours at the rated load)

The capacity factor of each plant is as shown in Table 4.3-1, but they are set as given below in consideration of operational changes to be made from 1994 associated with the planned remodeling of Part II.

The ordinary annual capacity factor shall be that of the Plan for 1993 for Part II, and those of the Plans for 1993 and 1994 for Part III. The capacity factor at the year of periodical inspection shall be determined from the performance in 1991 and the Plan for 1992 for Part II, and from the Plan for 1995 for Part III.

(2) Plant Efficiency

Part II:	35.01%	(at the rated load)
	33.2%	(average: from efficiency calculation of 1991, Melnik Power Station)
Part III:	36.09%	(at the rated load)
	33.6%	(average: from efficiency calculation of 1991, Melnik Power Station)

(3) Periodical Inspection

The periodical inspection is carried out in two kinds of full inspection and simple inspection. The full inspection, which takes about 6 months, is carried out once every four years for 110 MW units of Part II and once for every five years for the 500 MW unit of Part III. A simple inspection, which takes about 2 weeks, is carried out every year. For Part II, full inspections are planned not to overlap for two or more units. The full inspection has been scheduled to be made on a single unit each year so that one cycle for 4 units is completed in four years.

Long-term shutdowns are planned during 1994 to 1996 for Unit Nos. 9 and 10 of Part II and during 1995 to 1998 for Unit Nos. 7 and 8 of Part II for replacement of the turbine and generator and remodeling each unit to a cogeneration system. Thus, the above-mentioned cycle does not apply during that period.

Schedules of shutdowns for maintenance and plans for remodeling of Part II and Part III of the Melnik Power Station are outlined in Fig. 4.3-1.

(4) Concentration of SO_2 Emission and Regulatory Limits

Flue gas characteristics of each unit calculated from fuel characteristics and plant efficiencies obtained from the Melnik Power Station are as shown in Table 4.3-2. Data used for the calculation are given in Table 4.3-3.

Calculated concentrations of SO_2 emission are as follows:

Part II: 4,840 mg/m^3N (as dry and O_2 = 6% base)

Part III: 4,840 mg/m^3N (as dry and O_2 = 6% base)

a. Emission by unit

Part II : 64.4 t/h x 1.5(%) x 64/32 = 1.93 t/h (1 unit)

Part III: 283.7 t/h x 1.5(%) x 64/32 = 8.51 t/h

b. Regulatory limits on SO_2 emission after October 1996

Part II : DeSOx Efficiency more than 70%
(SO_2 concentration 1,450 mg/m^3N or less)

Part III: DeSOx Efficiency more than 85%
(SO_2 concentration 720 mg/m^3N or less)

c. SO_2 emission of each unit after October 1996 (at 100% load)

Part II : 1,450 mg/m^3N x 461,000 m^3N/h x (21-8.0)/15 = 0.58 t/h (per unit)

Part III: 720 mg/m^3N x 1,954,000 m^3N/h x (21-7.5)/15 = 1.27 t/h

d. Amount of removed SO_2 after October 1996 (Maximum per year)

Part II : 1.93 t/h - 0.58 t/h = 1.35 t (per unit)
1.35 t/h x 4 units x 5,081 h = 27,437 t/year

Part III: 8.51 t/h - 1.27 t/h = 7.24 t/h
7.24 t/h x 4,468 h = 32,348 t/year

4.3.2 Design Conditions for FGD

(1) Conditions at FGD Inlet and Outlet

Inlet and outlet conditions of FGD are shown in Table 4.3-4. The inlet flue gas volume in the conditions is given as a value of two effective digits by rounding up the value shown in Table 4.3-2 in consideration of load swings and fluctuations of power plants. The design total deSOx efficiency is assumed to be the same as the regulatory value (see Note).

In addition, to avoid problems caused by sulfuric acid mist in facilities downstream of the FGD, the minimum flue gas temperature at stack inlet was set for the case of the wet type limestone gypsum method in consideration of the brown coal fuel which causes high concentrations of both moisture and SO_3 concentration in flue gas. It should be noted that the concentration of sulfuric gas (SO_3) in flue gas was estimated from experiences at EPDC because no analysis data were available. Furthermore, concentrations of hydrogen chloride (HCl) and hydrogen fluoride (HF) in flue gas were calculated using coal analysis data. The data used in such calculations are shown in Table 4.3-5. Other inlet conditions of FGD are as shown in Table 4.3-2.

Note: "The Total DeSOx Efficiency" in this report is defined by the following expression:

$$\left(1 - \frac{[\textit{Quantity of } SO_2 \textit{ at stack outlet}]}{[\textit{Quantity of } SO_2 \textit{ at boiler outlet}]}\right) \times 100(\%)$$

(2) Coal Characteristics

Coal characteristics used in the study are shown in Table 4.3-6. Such coal characteristics are set as follows:

The Melnik Power Station is using about 35 kinds of lignite, and all of them are domestic coal from northern Bohemia. According to past data, there had been some times when heating value of coal was inadequate to ensure the necessary load. Recent data, however, indicate that coal characteristics are getting stable and such characteristics are estimated also for future supplies.

Results of analysis of coal sampled at the Melnik Power Station on May 20 and July 20 and analyzed in Japan are shown in Table 4.3-7. Six (6) kinds of coal of known origin represent major sources of coal supply accounting for about 80% of coal to be used at the Melnik Power Station. Mean values on the six (6) kinds of coal therefore are assumed to be the coal characteristics for the study of FGD.

Brown coal characteristics for determining the amount of SO_2 emission from the Melnik Power Station show, however, total moisture of 30.2%, heating value of 3,720 kcal and sulfur content in coal of 1.5% (dry basis) as fuel characteristics.

The total moisture of 30.2% given by the Melnik Power Station is used. As for the calorific value, the value given by the Melnik Power Station and the mean value of 3,680 kcal/kg (air-dry basis) obtained on the six (6) major kinds of coal are nearly in agreement, so that the mean value is employed. As for the sulfur content in coal, the data for past 10 years shown in Fig. 4.3-2 are not more than 1.3% (air-dry basis), and it is assumed to be 1.5% (dry basis) because such values given by the Power Station would be appropriate also for the future.

It should be noted, however, from the results of analysis made on coal samples that care must be paid to DeSOx reactions and material corrosions because of the high level of chlorine and fluorine contents in coal

(3) Operational Range of FGD

Power plants of the Melnik Power Station are usually operated, at both Part II and Part III, at base load of more than 50% load, and design operation ranges of FGDs are assumed to be the same as those of the power plants as follows:

Part II: 63.6-100% rated load (corresponding to 70-110 MW)

Part III: 60.0-100% rated load (corresponding to 300-500 MW)

(4) Source of Water for FGD

Water for all purposes, such as plant water, condenser cooling water, bearing cooling water, ash treatment water and water for miscellaneous use, used at the Melnik Power Station is currently obtained from the Labe River. Water from the Labe River has no problem as to quality and it is to be used also for the FGDs.

There are several possible ways to get water, such as the way to branch the discharge side of the condenser cooling water of Part II and the way to branch the intake side of the condenser cooling water, but the water intake facility will be studied at Conceptual Design.

Results of quality analysis made on plant water and discharge water at the power station by the Study Team on May and July 1992 are shown in Table 4.3-8.

(5) Method of Waste Water Ttreatment

Waste water from FGD will be discharged to the Labe River if the FGD to be selected causes waste water. If such is a case, installation of facilities for removing heavy metals and other components from FGD waste water will be studied not to affect the water quality and ecology of the river.

The river water quality standards are shown in Table 4.3-9.

(6) Ash Characteristics

Ash was prepared from coal samples collected at the Melnik Power Station during the survey made in May and July 1992, and results of analysis on such ash are shown in Table 4.3-10.

(7) Dust at Electrostatic Precipitator (ESP) Inlet and Outlet

Dust concentrations at ESP inlet, obtained from past performance, are shown below.

110 MW unit: Max. 54.0 g/m^3_N, Dry
500 MW unit: Max. 85.0 g/m^3_N, Dry

It is judged that the dust concentrations at ESP inlet shown above are consistent with their expected performance at both Part II and Part III on the grounds that the ESP of Part II were just renewed and that those at Part III are new units installed in the 1980s. It is therefore determined to use 100 mg/m^3_N as the dust concentration at ESP outlet for the design of FGD.

(8) Method of Ash Handling and Ash Disposal Area

The amount of ash generated at the Melnik Power Station is about 2.5 million tons per year, and all ash is made into mixed slurry of flyash and clinker, and disposed by ash handling pumps to an ash disposal area which is about 1.5 km away from the Power Station.

The ash disposal area is divided into two to north and south sections having a total capacity of about 6 million cubic meters. The ash slurry is currently disposed to the north section, and banking is being made for the south section. The ash disposal height has been planned to be GL+210.5 m, and the ash is to reach that height in 1998. The use of old coal mines, about 150 km from the Power Station, is being planned as an ash disposal area when the current ash disposal area is full, and such old coal mines will be used if FGD by-products are to be disposed.

The ash disposal area has a structure where a bank is made with nearby soil (fine sand) for the first mound. Further mounds are made with disposed ash and soil. The ash disposal area is surrounded by a gutter to collect water permeated from the ash disposal area. The water collected in the gutter is reused for spraying on the ash disposal area.Water which overflows the ash disposal area after sedimentation is discharged to the Labe River. Water from the river is also used for making up the water for ash treating slurry.

Results of quality analysis of water permeated from the ash disposal area are shown in Table 4.3-8.

(9) Space of FGD Installation

Fig. 4.3-3 shows a general plan for the space available for FGD installation. The coal train defreezing tunnel and the warehouse present in the space should be removed.

Note that the installation space is showing a space available for installation of major equipment, and a further detailed examination is necessary for installation of auxiliary equipment, ducts, pipes and cables.

As shown in the general plan described above, in addition, a consideration must be given to duct arrangement because a coal conveyer is passing through the space for FGD installation, some space is required for roads for Part III and an allowance of upper 15 m is required.

4.3.3 Unit Prices of Utilities

Unit prices of utilities as of July 1992, the time of economic comparison of various FGD methods, are shown in Table 4.3-11.

Exchange rates of Czechoslovak crown (kčs) with other currencies as of July 1992 were as follows:

1 kčs = 4.634 yen
1 kčs = 0.036 US$
1 kčs = 0.053 DM

4.3.4 User, Supply Volume and Unit Price of Gypsum

British Gypsum is planning to build a gypsum board factory at a place 1.5 km from the Power Station, and gypsum produced as a by-product of the FGD process is to be supplied to the factory. A basic agreement for supply of gypsum has already been made. Conditions of supply are as follows:

(1) Unit price : -5 DM (German mark)/ton

(It should be noted that the Melnik Power Station participates, as an investor, in the operation of the gypsum board factory, and it is estimated that the negative pricing of gypsum will all be compensated.)

(2) Supply volume: 92,000 ton/year (All gypsum (dry base) from Part III is assumed.)

4.3.5 User and Unit Price of Sulfuric Acid

The marketability of sulfuric acid in Czechoslovakia has not yet been studied and details are not known. There is a comparatively large scale chemical plant in Spolana-Neratovice not far from Melnik, and sulfuric acid can be used at the plant. In the present economic comparison, the price of sulfuric acid was set to be zero (0) compensating between sale and disposal.

4.3.6 Number of Years for Depreciation and Discount Rate

Standard rates of depreciation have been set for each equipment and industries in Czechoslovakia, but no standard rate has been set for FGDs. In the present economic comparison, a case of comparatively similar chemical plant was applied to the FGD with a linear depreciation rate of 8% and residual value of zero (0), i.e., the equipment is assumed to be fully depreciated in 12.5 years.

The discount rate was assumed to be 10% for economic comparison.

Table 4.3-1 The Capacity Factor of Melnik Power Station

(%)

Part	Unit No.	Actual Data in 1991	Planning Data				Ordinary Year	Year of Periodical Inspection	Average
			1992	1993	1994	1995			
II	7	30.96	69	66	70	71	66	34	58
	8	64.37	37	69	70	71			
	9	63.83	66	63	19	14			
	10	69.94	63	61	70	12			
III	11	55.86	51	59	61	15	60	15	51

(Periodical Inspection shall be carried out;
once every four years for Part II
and once every five years for Part III.)

$$* \text{ Capacity Factor} = \frac{\text{Annual Electricity Output (MWh)}}{\text{Total Available Electricity Output (MW)} \times 8{,}760\ \text{h}} \times 100\%$$

Table 4.3-2 Calculated Flue Gas Specification

Item	Unit	Value
(1) Melnik II (1 Unit)		
Coal Consumption (as Dry base)	t/h	64.4
O_2 Concentration (ESP Outlet, as Dry base)	%	8.0
H_2O Concentration (ESP Outlet)	%	13.0
Flue Gas Flow at APH Outlet (as Wet base)	m^3N/h	521,000
Flue Gas Flow at APH Outlet (as Dry base)	m^3N/h	461,000
SO_2 Concentration (as O_2 =6% and Dry base)	mg/m^3N	4,840
Plant Efficiency	%	35.01
(2) Melnik III		
Coal Consumption (as Dry base)	t/h	283.7
O_2 Concentration (ESP Outlet, as Dry base)	%	7.5
H_2O Concentration (ESP Outlet)	%	13.4
Flue Gas Flow at APH Outlet (as Wet base)	m^3N/h	2,217,000
Flue Gas Flow at APH Outlet (as Dry base)	m^3N/h	1,954,000
SO_2 Concentration (as O_2 = 6% and Dry base)	mg/m^3N	4,840
Plant Efficiency	%	36.09

Table 4.3-3 Calculation of Flue Gas Amount (1/2)

(1) Coal Properties

a. Total moisture (W)	30.2%
b. Carbon [C]	44.22% (DRY)
c. Hydrogen [H]	3.42% (DRY)
d. Nitrogen [N]	0.81% (DRY)
e. Oxygen [O]	12.01% (DRY)
f. Sulphur [S]	1.5% (DRY)

(2) Coal Consumption (Fcd)

a. Melnik II (as Dry) (1 unit)	64.4 ton/h
b. Melnik III (as Dry)	283.7 ton/h

(3) Calculation with Theoritical Formula

a. Theoritical air

$$A_o\ (m^3N/kg\text{-}Fuel) = \{8.89x[C]+26.7x([H]-[O]/8)+3.33x[S]\}\ x(100-W)/100x1/100$$

$$= 3.136$$

b. Theoritical flue gas

$$G_o\ (m^3N/kg\text{-}Fuel) = 0.79xA_o+\Big[(1.867x[C]+11.2x[H]+0.8[N]+0.7x[S])\ x\{(100-W)/100\}+(1.244xW)\Big]x1/100$$

$$= 3.709$$

c. Wet combustion gas

$$Gw\ (m^3N/kg\text{-}Fuel) = G_o+(m-1)xA_o$$

$m = 21/21-O_2$

Melnik II $O_2 = 8.0\%$

Melnik III $O_2 = 7.5\%$

d. Dry combustion gas

$$Gd\ (m^3N/kg\text{-}fuel) = Gw - \frac{0.224}{18}\Big[9x[H]x\{(100-W)/100\}+W\Big]$$

Table 4.3-3 Calculation of Flue Gas Amount (2/2)

e. Plant efficiency

$\eta II = 0.3501$

$\eta III = 0.3609$

f. Coal consumption (as dry base)

Fcd(t/h) = 860 x (MW)/η/(calorific value)

g. Coal consumption (as received)

Fcw(t/h) = Fcd x 100/(100-w)

h. Wet flue gas

Qw (m^3N/h) = (Fcw x Gw) x 10^3

i. Dry flue gas

Qd (m^3N/h) = (Fcw x Gd) x 10^3

j. H_2O concentration

$(\frac{Qw}{Qd} - 1) \times 100$ (%)

k. SO_2 amount

SO_2 (kg/h) = $([S]/100) \times (1 - \frac{30.2}{100}) \times (Fcw \times 10^3) \times \frac{64}{32}$

l. SO_2 concentration (as dry, O_2 = 6%)

$[SO_2]$ (mg/m^3N) = $SO_2 \times 10^6 / \{Qd \times \frac{(21-O_2)}{(21-6)}\}$

Table 4.3-4 DeSOx Design Value (1/2)

(1) Inlet Condition

Item	Unit	Value
(1) Melnik II (1 Unit)		
Flue Gas Amount (as Wet base)	m^3N/h	530,000
SO_2 Concentration (as O_2 = 6% and Dry base)	mg/m^3N	4,840
O_2 Concentration (ESP Outlet, as Dry base))	%	8.0
H_2O Concentration (ESP Outlet)	%	13.0
HCI Concentration (as O_2 = 6% and Dry base)	mg/m^3N	19.1
HF Concentration (as O_2 = 6% and Dry base)	mg/m^3N	94.6
(2) Melnik III		
Flue Gas Amount (as Wet base)	m^3N/h	2,300,000
SO_2 Concentration (as O_2 = 6% and Dry base)	mg/m^3N	4,840
O_2 Concentration (ESP Outlet, as Dry base)	%	7.5
H_2O Concentration (ESP Outlet)	%	13.4
HCI Concentration (as O_2 = 6% and Dry base)	mg/m^3N	19.1
HF Concentration (as O_2 = 6% and Dry base)	mg/m^3N	94.7

Table 4.3-4 DeSOx Design Value (2/2)

(2) Outlet Condition

Item	Unit	Value
(1) Melnik II (1 Unit)		
Stack Outlet Temperature	°C	100 or more
DeSOx Efficiency (at Stack)	%	70<
(Reference Value) SO_2 Concentration (as O_2 = 6% & dry base)	$mg/m^3{}_N$	1,450
(2) Melnik III		
Stack Outlet Temperature	°C	100 or more
DeSOx Efficiency (at Stack)	%	85<
(Reference Value) SO_2 Concentration (as O_2 = 6% & dry base)	$mg/m^3{}_N$	720

(3) For SO_3 Dew Point Consideration

Item	Unit	Value
SO_3 Conversion Ratio	%	Max 1
(1) Melnik II (1 Unit)		
SO_3 Concentration (as O_2 = 6% and Dry base)	$mg/m^3{}_N$	48.4
H_2O Concentration (ESP Outlet)	%	13.0
(2) Melnik III		
SO_3 Concentration (as O_2 = 6% and Dry base)	$mg/m^3{}_N$	48.4
H_2O Concentration (ESP Outlet)	%	13.4

Table 4.3-5 Calculation of [HCl] and [HF] Concentration in Flue Gas

		Melnik II (4 unit)	Melnik III
[1]	Coal Consumption (as Dry base) (t/h)	257.6	283.7
[2]	Chlorine Concentration in Coal (mg/kg) (analyzed from the fuel sample)	116	
[3]	Fluorine Concentration in Coal (mg/kg) (analyzed from the fuel sample)	587	
[4]	[Cl] atomic weight	35.5	
[5]	[F] atomic weight	19.0	
[6]	[HCl] molecular weight	36.5	
[7]	[HF] molecular weight	20.0	
[8]	Flue Gas Flow at APH Outlet (as Dry base) (m^3N/h)	1,844,000	1,954,000
[9]	[HCl] Arrival Rate from Boiler to DeSOx	0.995	
[10]	[HF] Arrival Rate from Boiler to DeSOx	0.950	
[HCl]	Concentration (Boiler outlet)		
	$[11] = \frac{[1] \times 10^3 \times [2] \times [6]/[4]}{[8]}$	19.22	19.24
[HF]	Concentration (Boiler outlet)		
	$[12] = \frac{[1] \times 10^3 \times [3] \times [7]/[5]}{[8]}$	99.60	99.68
[HCl]	Concentration at DeSOx Inlet [9] x [11]	19.1	19.1
[HF]	Concentration at DeSOx Inlet [10] x [12]	94.6	94.7

Table 4.3-6 Coal Properties

Item	Unit	Value
Calorific Value		
Air Dry Base	Kcal/kg	3,680
Dry Base	Kcal/kg	4,200
Dry Base	MJ/kg	17.84
Wet Base (as received)	Kcal/kg	2,930
Wet Base (as received)	MJ/kg	12.27
Total Moisture	%	30.2
Proximate Analysis (Air Dry base)		
Inherent Moisture	%	12.4
Volatile Component	%	30.1
Ash	%	33.4
Fixed Carbon	%	24.1
Ultimate Analysis		
Carbon	%	44.22
Hydrogen	%	3.42
Oxygen	%	12.01
Nitrogen	%	0.81
Sulfur	%	1.5
Ash	%	38.04
Chlorine	mg/kg	116
Fluorine (Tube Furnace Method) (Bomb Method)	mg/kg	587 (185)
Boron	mg/kg	43
Grindability	HGI	75

Table 4.3-7 Coal Analysis by EPDC

Sampling Date: May & July, 1992

Item	Unit	Mine							
		VZOREK #-2	VZOREK #-3	MERKVR	LEDVICE	HERKVES	KOMORANY	Total Average	Mix Coal
Lower Heating Value (AD)	kcal/kg	3,870	3,930	3,330	4,650	2,980	3,330	3,680	4,390
Proximate Analysis (AD)									
Inherent Moisture	%	9.3	8.8	15.5	16.8	11.5	12.7	12.4	9.6
Ash	%	33.9	33.6	34.0	18.0	43.3	37.7	33.4	28.0
Volotile Matter	%	31.2	32.2	29.5	33.1	26.1	28.7	30.1	35.0
Fixed Carbon	%	25.6	25.4	21.0	32.1	19.1	20.9	24.0	27.4
Fuel Ratio (F.C/V.M)	-	0.82	0.79	0.71	0.97	0.73	0.73	0.79	0.72
Ultimate Analysis (Dry)									
Carbon	%	44.76	44.75	41.85	58.36	35.49	40.12	44.22	50.21
Hydrogen	%	3.41	3.56	3.10	4.19	2.98	3.25	3.42	3.86
Sulphur	%	2.38	1.23	2.20	0.82	1.44	2.20	1.71	1.58
Nitrogen	%	0.95	0.72	0.88	0.91	0.66	0.72	0.81	0.93
Ash	%	37.38	36.84	40.24	21.68	48.93	43.18	38.04	30.97
Oxygen	%	11.12	12.90	11.73	14.04	10.50	10.45	11.79	12.45
Fluorine (Tube Furnace Method) (Bomb Method)	mg/kg	500	760	600 (180)	530 (150)	610 (140)	520 (260)	587 (185)	690
Chlorine	mg/kg	154	123	102	100	117	102	116	87
Boron	mg/kg	42	37	44	27	52	57	43	32

Note: AR: As Received Base, AD: Air Dry Base

Table 4.3-8 Water Analysis

Item	Unit	Cooling Water (River Water)		Discharged Water		Ash Pond Overflow Water	
Sampling Date		May, 1992	July, 1992	May, 1992	July, 1992	May, 1992	July, 1992
COD-Mn	mg/ℓ	8.0	7.7	10.0	9.2	5.1	1.4
COD-Cr	〃	62		62		9.0	
SS	〃	1>	7	1>	16	1>	6
Total Hardness	$CaCO_3$ mg/ℓ	150	170	150	160	190	430
Na^+	mg/ℓ	290	26.0	120	25.0	80.0	33.0
K^+	〃	20.0	7.8	18.0	7.0	9.8	1.5
Ca^{+2}	〃	43.0	9.3	43.0	8.9	57.0	19.0
Mg^{+2}	〃	16.0	44.0	14.0	44.0	12.0	150
CO_3^{-2}	〃	6>		6>		6>	
HCO_3^-	〃	76.0		73.0		49.0	
F^-	〃	0.2	0.1>	0.2	0.2	0.8	1.0
Cl^-	〃	27.0	29.0	27.0	29.0	27.0	32
SO_4^{-2}	〃	91.0	200	110	180	170	270
Cu^{+2}	〃	0.01>		0.01		0.01	
Zn^{+2}	〃	0.03		0.02		0.02	
Fe^{+2}	〃	0.28		0.29		0.20	
Mn^{+2}	〃	0.11		0.10		0.04	
CN	〃	0.1>		0.1>		0.1>	
Cd	〃	0.003>		0.003>		0.003>	
Pb	〃	0.02>		0.02>		0.02>	
Cr^{+6}	〃	0.01>		0.01		0.01>	
T-Hg	〃	0.0005>		0.005>		0.0005>	
O-P	〃	0.1>		0.1>		0.1>	

Table 4.3-9 River Water Quality Standards

Item	Unit	Limit	Item	Unit	Limit
O_2	mg/ℓ	min. 4	Pb	mg/ℓ	0.1
BSK	"	8	As	"	0.1
COD-Mn	"	20	Cu	"	0.1
COD-Cr	"	50	Cr	"	0.3
S^{2-}	"	0.02	Cr^{vi}	"	0.05
pH	"	6.0 ~ 9.0	CO	"	0.1
RL	"	1,000	Ni	"	0.15
Fe	"	2.0	Zn	"	0.2
Mn	"	0.5	V	"	0.1
$N\text{-}NH_4^-$	"	2.5	Ag	"	0.05
NH_3	"	0.5	Se	"	0.05
$N\text{-}NO_2^-$	"	0.05	Ba	"	2.0
$N\text{-}NO_3^-$	"	11	Be	"	0.001
N-org	"	3.0	Aa	Bq/ℓ	0.5
P	"	0.4	Ab	"	2.0
Cl^-	"	350	Ra226	"	0.3
SO_4^{2-}	"	300	U	mg	0.1
Ca	"	300	$H_3(T)$	Bq/ℓ	5,000
Mg	"	200	Sr90+Y90	"	0.5
F^-	"	1.5	Cs137	"	1.0
FN1	"	0.1	Coli	KTJ	200,000
PAL-A	"	1.0	Fecoli	KTJ/ℓ	40,000
NEL	"	0.2	Enko	KTJ/ℓ	20,000
CN^-	"	0.2	BZ	mg/ℓ	0.05
Cl_2	"	0.05	CB	"	0.01
EOCl	"	0.025	DCB	"	0.001
B	"	0.5	PCB	ng/ℓ	25
Hg	"	0.001	BZP	ng/ℓ	50
Cd	"	0.015			

Note: All values are max. limit except for "O_2".

Table 4.3-10 Ash Analysis by EPDC (1/2)

Sampling Date: May, 1992

Item	Unit	Mine								
		VZOREK #-2	VZOREK #-3	MERKVR	LEDVICE	HERKVES	KOMORANY	Total Average	Mix Coal	ESP-Ash #-3
Ash Analysis (Dry)										
SiO_2	%	49.90	53.83	55.72	51.43	54.84	56.06	53.63	46.13	42.12
Al_2O_2	%	27.27	29.24	21.94	26.00	26.62	26.83	26.32	27.17	31.19
Fe_2O_2	%	10.54	7.14	10.94	5.49	4.68	4.99	7.30	11.30	6.53
CaO	%	2.33	1.58	2.29	2.18	0.78	1.01	1.70	2.76	1.88
MgO	%	1.43	1.25	2.29	1.37	0.90	0.98	1.37	1.59	1.08
Na_2O	%	0.96	0.84	1.46	1.52	1.02	1.14	1.16	0.08	2.42
K_2O	%	1.52	1.46	1.01	1.44	2.21	1.97	1.60	1.50	2.11
SO_3	%	1.79	1.02	2.87	2.36	0.64	0.87	1.64	2.09	0.33
TiO_2	%	2.37	2.92	3.21	3.10	1.86	2.34	2.63	2.95	4.63
P_2O_5	%	0.36	0.45	0.49	0.43	0.31	0.33	0.40	0.55	0.72
V_2O_5	%	0.03	0.03	0.03	0.04	0.02	0.02	0.03	0.03	0.02
MnO	%	0.04	0.04	0.08	0.06	0.14	0.36	0.12	0.12	0.05

Table 4.3-10 Ash Analysis by EPDC (Ash Fusion Temperature) (2/2)

Sampling Date: May, 1992

Item	Unit	Mine		
		VZOREK #2	VZOREK #3	Mix Coal
Oxidation Atmosphere				
Initial Deformation	°C	1,430	>1,450	1,440
Softening	°C	>1,450	>1,450	>1,450
Melting	°C	>1,450	>1,450	>1,450
Fluidizing	°C	>1,450	>1,450	>1,450
Reduction Atmosphere				
Initial Deformation	°C	1,350	1,400	1,340
Softening	°C	1,390	>1,450	1,390
Melting	°C	1,400	>1,450	1,400
Fluidizing	°C	1,420	>1,450	1,420

Table 4.3-11 Unit Price of Utilities

Item	Unit	Value	Remarks
(1) Limestone ($CaCO_3$)	kčs/ton	130 (= 68 + 62) 212 (= 150 + 62)	• Particle size (22.5 ~ 80 mm) 95% purity • Crashed 95% purity
(2) Lime (CaO)	kčs/ton	812 (= 750 + 62) 1012 (= 950 + 62)	• Pieces • Dust
(3) Slaked Lime ($Ca(OH)_2$)	kčs/ton	912 (= 850 + 62) 1012 (= 950 + 62)	• Pieces • Dust
(4) Activated Carbon	kčs/ton	377,000	2,000 DM, 1 kčs = 0.053 DM
(5) Caustic Soda (NaOH)	kčs/kg	3.89	based on 45% concentration
(6) Sulfuric Acid (H_2SO_4)	kčs/kg	1.90 ~ 2.00	
(7) Auxiliary Steam	kčs/ton	Part II 125 Part III 125	
(8) Auxiliary Power	kčs/kwh	Part II 0.477 Part III 0.436	
(9) Law Water	kčs/m^3	0.54	river water

* As of end of July, 1992.

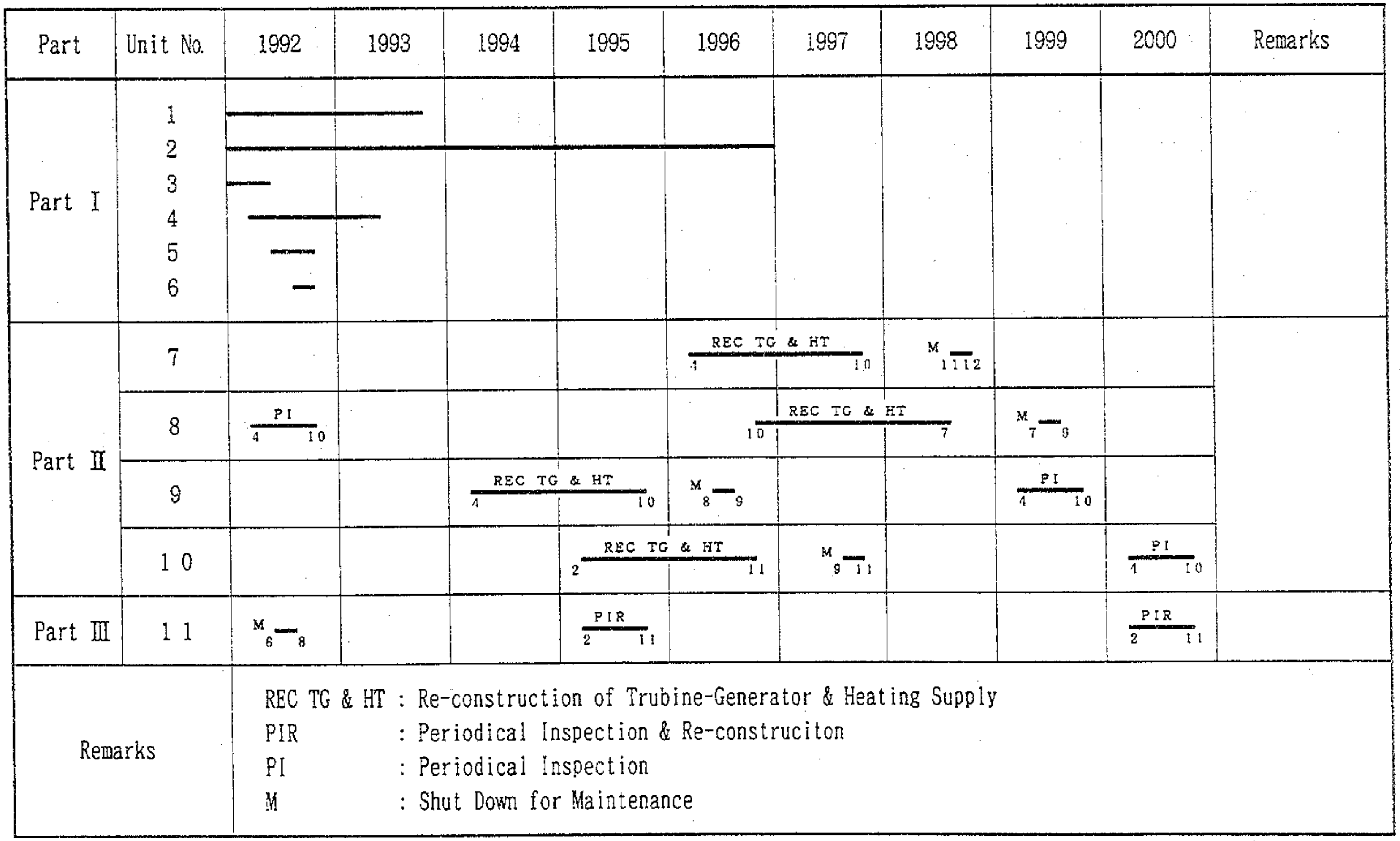


Fig 4.3-1 MAINTENANCE SCHEDULE OF THE MELNIK POWER STATION

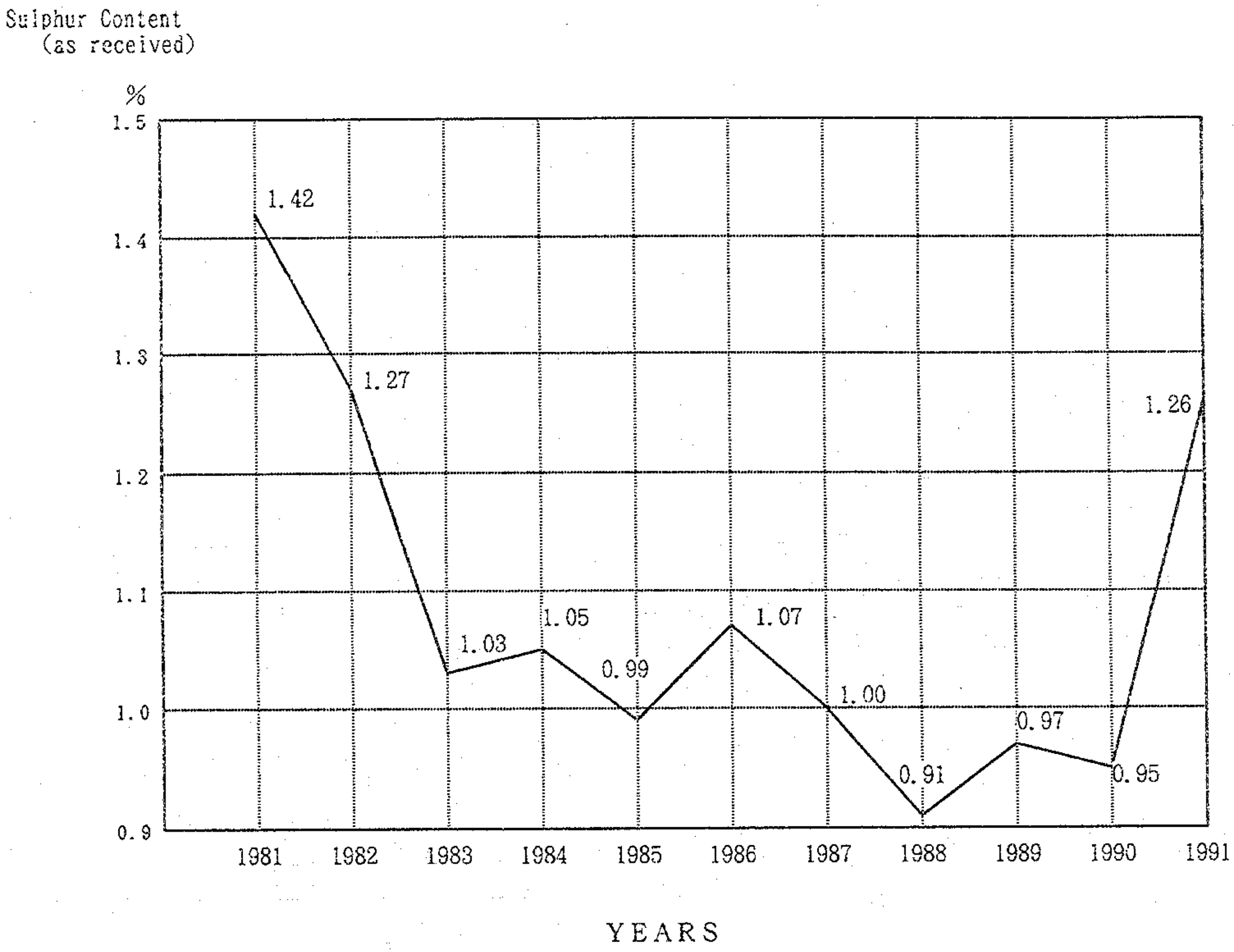
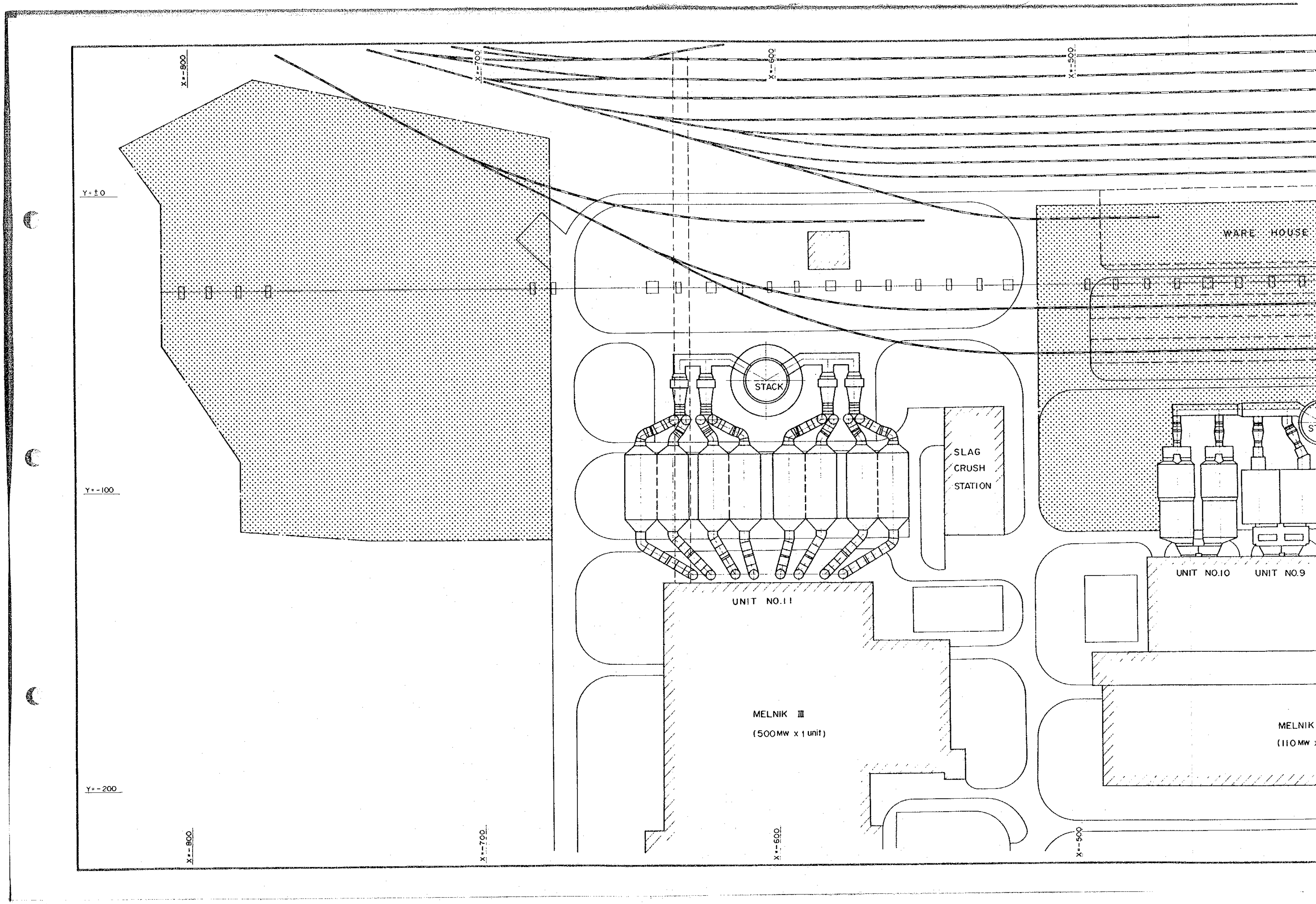


Fig.4.3-2 THE TREND OF SULPHUR CONTENT IN BURNED COAL SINCE 1981


X=-800
X=-700
X=-600
X=-500
Y=±0
Y=-100
Y=-200
WARE HOUSE
STACK
SLAG
CRUSH
STATION
UNIT NO.11
UNIT NO.10
UNIT NO.9
MELNIK III
(500MW x 1 unit)
MELNIK
(110 MW

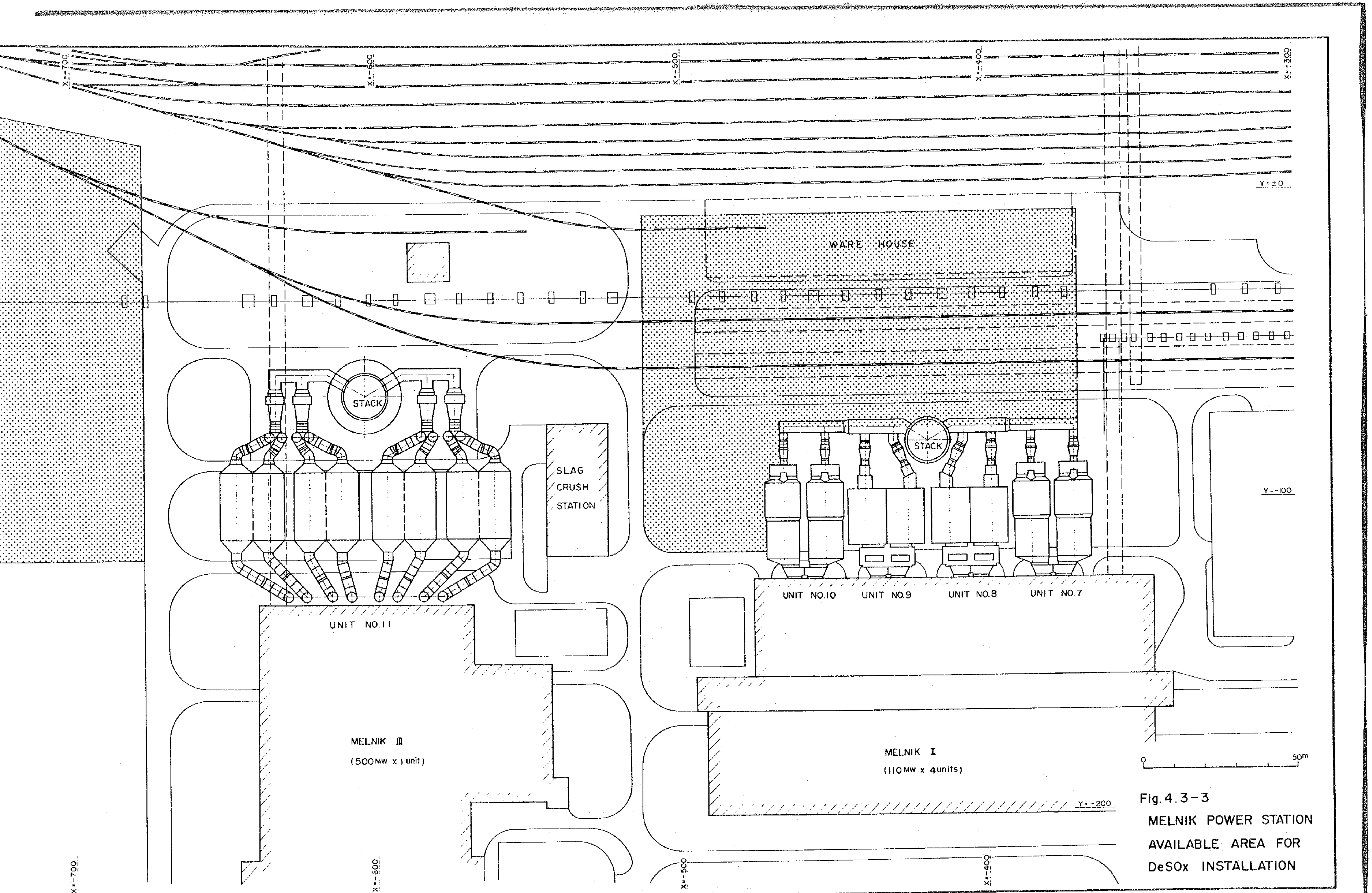


Fig. 4.3-3
MELNIK POWER STATION
AVAILABLE AREA FOR
DeSOx INSTALLATION

4.4 Study on Combination of Power Plants and FGDs

The study on the combination of FGDs for power plants of the Melnik Power Station must be conducted from the two viewpoints of technical conditions and economy of FGDs in considerations of conditions specific to the Melnik Power Station.

In addition, the capacity of treated gas volume and DeSOx performance of FGDs to be installed to power plants must be studied to lower the concentration of SO_2 emission to a level which meets the deSOx efficiency specified by the New Clean Air Act which is to be enforced from October 1996.

Possible combinations are selected in this Section, and a study is made to find out which combination is appropriate for the Melnik Power Station.

4.4.1 Study Conditions

Conditions specific to the Melnik Power Station are shown below.

(1) The total deSOx efficiency must be over 70% (equivalent to below 1,450 mg/m^3_N in outlet SO_2 concentration with 1.5% sulfur content in coal) for Unit Nos. 7 to 10 of Part II, and over 85% (equivalent to below 720 mg/m^3_N in outlet SO_2 concentration with 1.5% sulfur content in coal) for Unit No. 11 of Part III.

It should be noted that the emission regulation applies to individual emission sources (i.e. each boiler), and it is not allowed to employ a method to achieve an overall deSOx efficiency of the whole Power Station which would have a satisfactory deSOx efficiency when the whole Power Station is counted as a power unit.

(2) Spaces available for installation of FGDs are as shown in Fig. 4.3-3, and the coal train defreezing tunnel and the maintenance house must be removed for FGD installation of Part II.

(3) The distance between the existing boiler house and the ESP is only about 20 m for Unit No. 11 of Part III. For Unit Nos. 7 through 10 of

Part II, the distance is only about 7 m including the section of vertical duct to the ESP, not much space is available. Side views to the Power Station are shown in Figs. 4.4-1 and 4.4-2 which allow to understand the boiler house and ESP layouts.

(4) The stacks are of shared type. The No. 3 stack is used by four 110 MW units, the No. 4 stack by one 500 MW unit, and each of the Nos. 1 and 2 stacks by three 55 MW units.

The technical conditions of FGDs for combination are as follows:

(1) The maximum capacity of FGDs is set to be 500 MW to 700 MW equivalent from experiences, although it depends on the method.

(2) The maximum deSOx efficiency is on the order of 95%.

4.4.2 Basic Principles

It is generally said that devices show more economic merits when they are greater in capacity and higher in modularity and efficiency. On the other hand, a deSOx efficiency specific to each emission source is applied for the case of the Melnik Power Station, and thus it is necessary basically to install an FGD for each boiler. For the case of Part II which has four emission sources, for example, it is necessary to install an FGD of 70% in total deSOx efficiency to each emission source, and it is not allowed to install one FGD of 94% in the total deSOx efficiency to each of the three units and no FGD to one unit although such combination would reduce the total emission to below the level which would meet the regulation if such scheme were allowed.

In studying combinations therefore, Part III, of which required deSOx efficiency is different from others, is unconditionally separated. For Part II consisting of four units, possible combinations such as the "unit-to-unit" method where one FGD is installed for each unit, the "shared" method where a single large-capacity FGD is installed to take care the all four units, and the "mixed" method which is a certain mixture of the "unit-to-unit" method and the "shared" method are examined and a method which is optimum technically and economically is selected below.

Incorporating the above-mentioned concept and the study conditions discussed in the previous Paragraph, a method of combination is selected and DeSOx methods are examined according to the following basic principles below.

(1) An FGD of 500 MW equivalent is installed separately for the Unit No. 11 of Part III because the unit is as large as 500 MW in the output capacity and the deSOx efficiency limit for the unit is different from those of other units.

(2) The Absorbent Injection Methods are not Included in the FGD Methods to be Examined and Compared.

The absorbent injection methods (limestone injection into furnace and/or slaked lime injection into duct) show a deSOx efficiency on the order of 30 to 40% only by injection of absorbent into furnace or duct. For meeting the regulations at Part II of the Melnik Power Station, however, the deSOx efficiency of 70% or more is required when FGDs are installed with the "unit-to-unit" method for each power plant unit. To raise the deSOx efficiency to above 70%, it is necessary to add a water-spraying reaction tower to each unit in addition to the absorbent injection method. There is no space available for installation between the existing boiler house and the duct collector at Part II, and it would therefore be necessary to install the tower downstream of the existing ESP. If the tower is installed downstream of the ESP, an ESP must further be added in downstream of the tower, and the merit of the absorbent injection method requiring a smaller remodeling would be lost.

Since required deSOx efficiency for Part III is over 85%, the absorbent injection methods are not applicable for Part III.

The absorbent injection methods should be thus excluded from methods to be examined and compared.

(3) The Spray-Dryer Method is Considered as a System Having a Secondary Dust Collector.

A large systems of spray-dryer method equivalent to 200 MW and greater is made by changing the number of standard modular Spray-Dryer Absorbers (SDA). At a newly constructed power plant, the components are arranged in the order of primary dust collector, SDA, secondary (main) dust collector, IDF and stack. Such a standard modular SDA is about 14 m in diameter. When a primary ESP is included, the size increases to about 20 m. The space available between existing boiler house and dust collector is only 6.8 m at Part II and 16 m at Part III, and it is impossible to install a primary dust collector and an SDA neither at Part II nor at Part III.

It is therefore assumed in studying the possibility of the spray-dryer method for the Melnik Power Station that the existing ESP is to be used as the primary dust collector and use the current available space for installation of the SDA and secondary dust collectors.

(4) The two methods of the "unit-to-unit" method and the "shared" method are considered for Unit Nos. 7 through 10 because the subsequent duct after the induced draft fan (IDF) are common to all units. In the "shared" method, the power units and the FGDs must be coordinated, and, in addition, some restrictions might arise on operation of each power plant unit.

4.4.3 Study Items on Combinations

"Combinations" can be classified into Cases I, II and III below in studying combinations for Part II according to the basic principles of 4.4.2. In addition, there are Subcase A and Subcase B for each of the cases.

Study items for such possible combinations are described below. A combination table of FGDs is shown in Table 4.4-1.

(Case I) To bundle Unit Nos. 7, 8, 9 and 10 and install a single FGD

Only one FGD of 440 MW equivalent is required in this case. This gives a large scale merit, and the duct work is also the simplest. The installation of this FGD is the most economical. Much restrictions arise on operation of the power plant units of Part II, and it is necessary to make the schedule for plant shutdown common to all units of Nos. 7, 8, 9 and 10 at the time of periodical inspection of the power plants as well as of inspection of the FGD.

(Case II) To bundle Unit Nos. 7 and 8 and Unit Nos. 9 and 10 and install two FGDs

Two FGDs of 220 MW equivalent are required in this case. It requires a larger installation space, and the scale merits are not as great as that in Case I. The power units are grouped into two blocks of two unit each, it provides more freedom in operation.

(Case III) To install an FGD for each of Unit Nos. 7, 8, 9 and 10

Four FGDs of 110 MW equivalent are required in this case. The scale merits are the smallest in this case. The duct work around the stack is also the most complicated in this case. Operation of each unit is not restricted by each other, and the operational freedom of power units is the largest in this case.

[Subcase A] To treat all flue gas with the deSOx efficiency of 70%

All gas from Part II is treated in this case, and the duct work is simple even when remodeling is included.

[Subcase B] To treat only 82.5% of all flue gas with the deSOx efficiency of 85%

Flue gas to be treated is partial, and the duct work plan will be complex inclusive of handling of existing ducts. The economy, on the other hand, improves because the gas volume to be treated by each FGD is smaller.

The number of possible combinations is 6 with three cases of Cases I, II and III and two subcases A and B for each of the cases.

4.4.4 Results of Studies on Combination

The following can be said in examining the FGD-related hardware for each case of the above-mentioned cases:

(1) The wet type limestone-gypsum method has been used in FGDs for 500 MW class coal fired power units, and no technical problem is expected in applying to any of the cases. The difference in the total equipment cost between Cases I and II, and Cases II and III is on the order of 3 to 4%, causing a scale merit.

(2) A unit system using reactors of up to about 800,000 m^3N/h is being employed in the spray-dryer method, and modular adsorption towers are used in the dry type activated coke adsorption method. Thus, when either of these methods is employed, there is no change in scale merits on the part of the FGD by Cases I, II and III.

(3) Past experiences indicate that the deSOx efficiency of over 70% can be achieved by any methods other than absorbent injection methods. For the case of Subcase A, therefore, it is possible to realize any combinations of power units and FGDs by any methods other than the absorbent injection methods.

When the wet type limestone-gypsum method is employed, however, it may be difficult sometimes to achieve stable operation of FGDs at relatively low deSOx efficiencies.

(4) DeSOx efficiencies of over 90% can be attained by the wet type limestone-gypsum method and the dry type activated coke adsorption method. For the case of the spray-dryer method on the other hand, the optimum operational range is on the order of 80%, but it is technically

possible to attain a deSOx efficiency of over 90%. Subcase B can be also applicable therefore for cases of these three methods.

In addition to the hardware related aspects mentioned above, examination of the cases from operational aspects results the following:

(1) Part II is planned to be remodeled, in two phases, into a cogeneration plant. The time when FGDs are to be installed is different, due to the plan, between Units Nos. 9 and 10 and Units Nos. 7 and 8. Case I is not realistic therefore in consideration of the schedule for installation of FGDs.

(2) The periodical inspection for Part II has been planned to occur for a single power unit every year to avoid overlaps in shutdown period of any two units. It is appropriate therefore to avoid overlapped shutdowns due to a periodical inspection of the FGD. Case III is appropriate to avoid such overlapped shutdowns.

The difference in equipment cost between Cases II and III occurs only in the case of the wet type limestone-gypsum method. The difference, however, is as small as 3 to 4%, and it can be said that Case III is the most realistic from the viewpoints of operational effectiveness and in consideration also of the secondary effects mentioned below.

The secondary effects which are expected with the employment of Case III are as follows:

- The use of FGDs of same type results in economy because design drawings, production drawings, technical examinations and so forth are common to all FGDs.

- Spare parts and stock parts for FGDs are common, and the interchangeability provides advantages in maintenance of FGDs.

Based on the results of examination made above, Case III-B will be employed for the wet type limestone-gypsum method, the spray-dryer method and the dry type activated coke adsorption method for economic comparison for employment of FGDs at Part II and discussed in the Section 4.5 with the case of "four same type FGDs of 110 MW equivalent."

As for the FGD for Part III, economic comparisons will be made for the case of "one FGD of 500 MW equivalent."

Table 4.4-1 Combination of DeSOx Plants Installation

		Unit	Part II				Part III	Remarks
			Unit No. 7	Unit No. 8	Unit No. 9	Unit No. 10	Unit No. 11	
Case I-A	Flue gas through Reactor	%	400 (382)				100 (95)	100% Flue gas rate in Part II is difined as the 100% load operation of 1 Unit Boiler. Figure in ( ) shows the value calculated with consideration of GGH leakage.
	DeSOx Eff. in the Reactor	%	>70 (73.5)				>85 (90)	
	Total DeSOx Eff.	%	>70				>85	
	SO_2 Emission	mg/m^3N	≤1,450				≤720	
Case I-B	Flue gas through Reactor	%	330 (320)					
	DeSOx Eff. in the Reactor	%	>85 (87.5)					
	Total DeSOx Eff.	%	>70					
	SOx Emission	mg/m^3N	≤1,450					
Case II-A	Flue gas through Reactor	%	200 (191)		200 (191)			
	DeSOx Eff. in the Reactor	%	>70 (73.5)		>70 (73.5)			
	Total DeSOx Eff.	%	>70		>70			
	SO_2 Emission	mg/m^3N	≤1,450		≤1,450			
Case II-B	Flue gas through Reactor	%	165 (160)		165 (160)			
	DeSOx Eff. in the Reactor	%	>85 (87.5)		>85 (87.5)			
	Total DeSOx Eff.	%	>70		>70			
	SO_2 Emission	mg/m^3N	≤1,450		≤1,450			
Case III-A	Flue gas through Reactor	%	100 (95.5)	100 (95.5)	100 (95.5)	100 (95.5)		
	DeSOx Eff. in the Reactor	%	>70 (73.5)	>70 (73.5)	>70 (73.5)	>70 (73.5)		
	Total DeSOx Eff.	%	>70	>70	>70	>70		
	SO_2 Emission	mg/m^3N	≤1,450	≤1,450	≤1,450	≤1,450		
Case III-B	Flue gas through Reactor	%	82.5(80)	82.5(80)	82.5(80)	82.5(80)		
	DeSOx Eff. in the Reactor	%	>85(>87.5)	>85(>87.5)	>85(>87.5)	>85(>87.5)		
	Total DeSOx Eff.	%	>70	>70	>70	>70		
	SO_2 Emission	mg/m^3N	≤1,450	≤1,450	≤1,450	≤1,450		

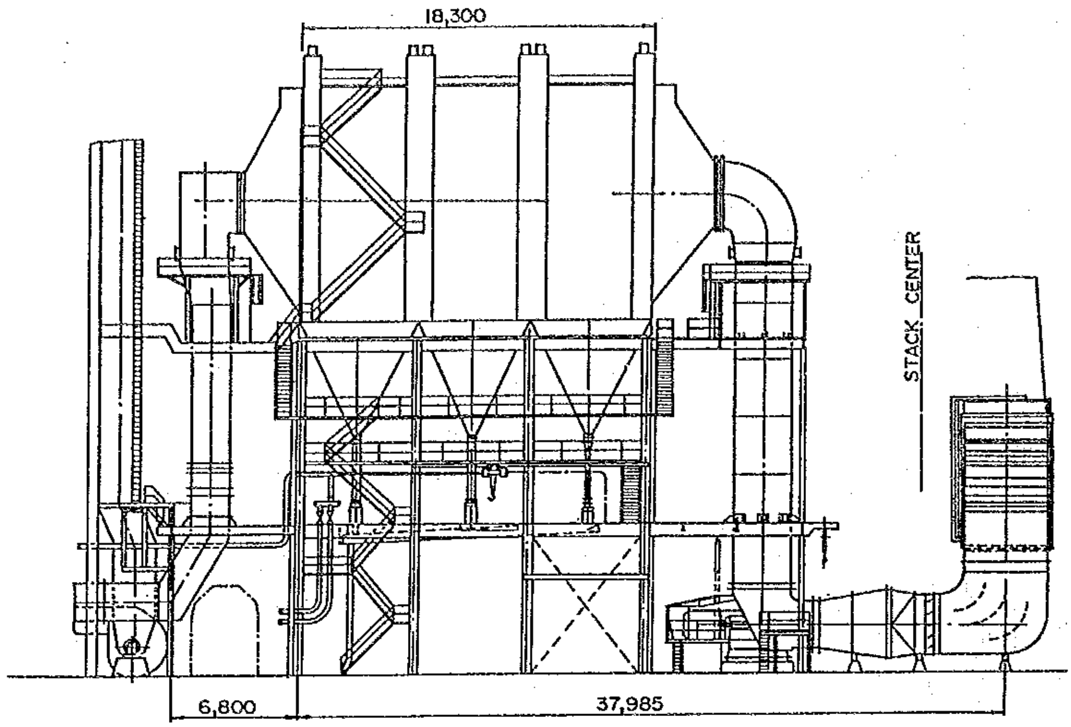


Fig.4.4.-1
PART I SIDE VIEW

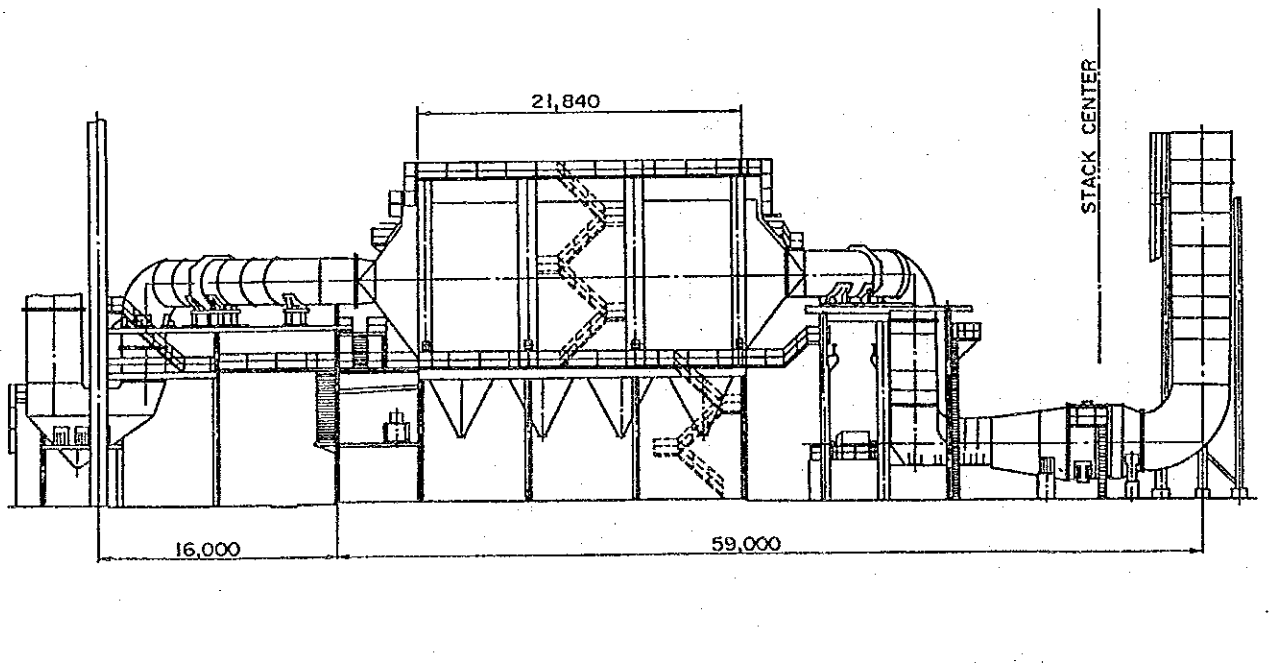


Fig.4.4.-2
PART II SIDE VIEW

4.5 Technical and Economic Comparison of FGD Methods under Evaluation

The seven FGD methods outlined and compared as to their technologies in Section 4.2 are evaluated in this section in reference to the FGD specifications for the Melnik Power Station set in Section 4.3 and combinations of FGD and power plant units examined in Section 4.4 to find out an FGD method which is the optimum for the Melnik Power Station.

4.5.1 Comparison Items

Technical and economic comparisons were made on the important items listed below.

(1) Items of Technical Comparison

a. Desulphurisation (DeSOx) performance
b. Dust removal performance
c. Technical maturity
d. Operational experiences in commercial plants
e. Reliability
f. Operational characteristics
g. Maintainability
h. By-products
i. Utilities
j. Waste water
k. Stack lining and treated gas reheating
l. Retrofit of existing facilities
m. Space for installation

(2) Items of Economic Comparison

a. Equipment and Installation cost
b. Running cost

4.5.2 Conditions for Technical and Economic Comparison

(1) Basic Conditions

Economic comparisons of the FGD methods are made using values of conditions examined for FGD methods in Section 4.3 and assuming the use of the combinations of "one FGD unit of 500 MW equivalent for Part III" and "four FGD units of 110 MW equivalent for Part II," which were the optimal combinations in the study made in Section 4.4.

(2) Method-specific Conditions

1) Wet Type Limestone-gypsum Processes (Spraying Tower Method and Jet Bubbling Method)

a. The gas coming out of the FGD is reheated for protection of duct and stack lining and prevention of flying of sulfuric mist.

b. About 92,000 t/year (dry base) of by-product gypsum (equivalent to that produced at Part III) is supplied to the nearby gypsum board factory, and the rest of gypsum is disposed.

c. Because of high chlorine content, gypsum and slurry to be disposed to a disposal area of non-permeable construction. The cost for making the disposal area non-permeable (the cost relating to prevention of permeation of harmful substances into ground) is therefore included in the running cost in economic comparison.

d. The deSOx efficiency is over 85% on 82.5% of flue gas to be treated for each unit of Part II, and over 85% on the whole flue gas to be treated for Part III.

2) Spray-dryer Method

a. No treated gas reheating is made because SO3 is also mostly removed for the case of the spray-dryer method.

b. All by-product is disposed to the disposal area of non-permeable construction because it contains sulfurous gypsum (H_2SO_3) and unreacted slaked lime ($Ca(OH)_2$) in addition to gypsum. The cost for making the disposal area of non-permeable is included in the installation cost as in the case of the wet type limestone-gypsum method.

c. Necessary amount of lime is possible to obtain.

d. The deSOx efficiency is over 85% in treating 82.5% of the flue gas for each unit of Part II, and over 85% in treating the whole flue gas for Part III.

3) Activated Coke Method

a. Marketable sulfuric acid (H_2SO_4) is recovered as a by-product. The sulfuric acid thus obtained should be salable, and the income from the sale of sulfuric acid shall be used to compensate the treatment cost.

b. Necessary amount of activated coke should be obtainable.

c. The deSOx efficiency is over 85% on 82.5% of flue gas to be treated for each unit of Part II, and 85% in treatment of whole flue gas of the unit for Part III.

4.5.3 Methods of Economic Comparison

The economic comparison is made by annual cost determined from equipment and installation cost and running cost. The comparison is made relative to the cost of the wet type limestone-gypsum process (100%). Each cost is estimated using the formulas given below.

(1) Levelized Annual Cost of the Equipment

$$[\text{Equipment and Installation cost}] \times \frac{0.10 \times (1+0.10)^{12.5}}{(1+0.10)^{12.5}-1}$$

(2) Running Cost (a - b)

a. [Hourly consumption of utility] x [Capacity factor] x 8,760 h x [Unit cost of utility]

b. [Hourly by-product generation] x [Capacity factor] x 8,760 h x [Unit sales price of by-product]

4.5.4 Results of Comparison

Tables 4.5-1 and 4.5-2 show the results of technical and economic comparisons of various FGD methods made in considerations of various factors specific to the Melnik Power Station.

Such results are summarized for each studied FGD method below.

(1) Wet Type Limestone-gypsum Method (Spraying Tower Method or Jet Bubbling Method)

Either wet type limestone-gypsum method is evaluated to be applicable to the Melnik Power Station from technical and economic comparisons.

a. The deSOx efficiency of over 95% is attainable. The wet type limestone-gypsum method is the most superior as to technical level, number of installations and reliability in consideration that the number of units which have been used for commercial coal fired utility boilers is about 200 units for the case of the spraying tower method and about 25 units for the case of the jet bubbling method.

b. The absorbent is limestone which is cheap and economically superior. Limestone is available from the Certovy-Sohody mine about 50 km from the Power Station and can be carried to the Power Station on railroad.

c. The equipment can be installed at the FGD installation space shown in Fig. 4.3-3.

d. A top view and a side view of an equipment layout of the spraying tower method are shown in Figs. 4.5-1 and 4.5-2, respectively, and those of the jet bubbling method are shown in Figs. 4.5-3 and 4.5-4, respectively. Either of these layout shows the case of one 500 MW class FGD unit of 85% in deSOx efficiency and four 110 MW class FGD units of 70% in deSOx efficiency representing the optimum combinations of power units and FGDs discussed in Section 4.4.

e. This method is advantaged in the economic comparison from the viewpoint of the operation cost shown in Table 4.5-2.

f. Considerations must be given to handling of waste water and by-product gypsum because of the use of coal which is high in chlorine and fluorine contents.

g. The grain size of limestone which is available to purchase is in the range of 22.5 to 80 mm, and a mill system is required for making limestone slurry (of particle sizes of not more than 43 μm).

(2) Semi-dry Method (Spray Dryer Method)

The technical comparison indicates that this method is adequate and applicable to the Melnik Power Station.

a. The deSOx efficiency of up to about 90% is attained by the spray dryer method. A large number of FGDs of this method are being used at coal fired power plants, and technologies of the method have been established to be a commercially viable level. In addition, the reliability of this method is as high as the wet type limestone-gypsum methods.

b. A plan view and a side view of an equipment layout are shown in Figs. 4.5-5 and 4.5-6, respectively. The layout shows the case of one 500 MW class FGD unit of 85% in deSOx efficiency and four 110 MW class FGD units of 70% in deSOx efficiency representing the optimum combinations of power units and FGDs discussed in Section 4.4.

c. The equipment cost of the FGD is relatively low, and it provides an economic advantage in equipment depreciation expense.

d. The spray dryer method requires the use of lime, which is more expensive relative to limestone, as absorbent. According to the survey made in Czech Republic, the price is 1,012 kcs/ton inclusive of transportation for lime and 130 kcs/ton for limestone. Lime therefore is about 7 times as expensive as limestone in consideration of the molar ratio of Ca/S which must be taken into account for removal of same amount of SO_2.

On the other hand, the by-product of the spray dryer method is a mixture of gypsum, slaked lime and coal ash. The amount of by-product to be disposed is about 115% of that produced by wet methods. The disposal area for such by-product must be that controlled by sheet curing in consideration of the by-product characteristics and the laws on disposal of industrial wastes.

The spray dryer method is disadvantaged in economy therefore from the viewpoint of the operation cost.

(3) Dry Methods (Activated Coke Adsorption Method)

The cases of the use of this method are very few. Three plants are operating commercially, and the technology has been established for commercial use. A plan view and a side view of equipment layout are shown in Fig. 4.5-7 and 4.5-8, respectively. The method, however, is considered inappropriate for the Melnik Power Station by the following reasons:

a. Activated coke used as adsorbent is hard to obtain

No activated coke suitable for use for FGDs is currently produced in Czechoslovakia. When all FGDs for Melnik Power Station are of the activated coke adsorption method, the annual activated coke requirement will be 12,900 tons. In Poland, about 1,500 tons of activated coke suitable for FGDs are produced annually for water treatment and other industrial use. In Germany, in addition, several tens of thousand tons of activated coke are produced annually.

Activated coke produced in Poland is economical du to the cheaper price, but inadequate in quantity. Activated coke produced in Germany may be adequate in quantity, but it is hardly economical due to the price which is on the order of 2,000 DM/ton in maximum. It should be noted that the amount of activated coke required for initial charge would be about 9,900 tons if all FGDs of the Melnik Power Station employ the activated coke adsorption method.

b. Problems are apprehended in by-product treatment

When sulfuric acid is recovered as a by-product, the amount of sulfuric acid recovered at Part II and Part III will be as much as about 470 tons per day, and problems will arise in its storage, transportation and sale. The coal used at the Melnik Power Station is high in chlorine and fluorine contents, and the flue gas is also high in hydrogen chlorine and hydrogen fluorine concentration. It therefore becomes necessary, in recovering sulfuric acid, to purify sulfuric acid. In addition, waste water from FGDs will also be high in chlorine and fluorine concentration, and it will become necessary to consider methods of waste water treatment.

It can be said, from the results of examination of various FGD systems discussed above, that the wet type limestone-gypsum method or the spray dryer method is applicable to both Part II and Part III of the Melnik Power Station from the viewpoints of both technical and economic comparisons.

To determine the best FGD method from those of two methods, it is necessary to make a comprehensive decision not only from comparisons on current aspects but also from future expectations, and examinations are made on the points depicted below.

(1) Additional Examination on the Aspect of Economic Comparison

a. The prevailing prices in Czechoslovakia at present are distorted in comparison with standard prices (International market prices) in former West European countries. As the country moves into market economy in line with the "Scenarios for Economic Reform," however, the prevailing prices will get close to the international market prices, and it is certain that utility costs will increase from their costs as of July 1992. Actual differences in running costs between wet limestone gypsum method and spray-dryer method therefore tend to get larger. When standard prices in former West European countries are used in place of the prevailing prices for a try, the wet type limestone-gypsum method gets more advantageous than the spray dryer method as shown in parentheses in Table 4.5-2.

b. The annual cost is the sum of the depreciation cost and the running cost for the period of equipment depreciation (12.5 years). The usual life period of equipment is on the order of 30 years, and the annual cost consists only of the running cost for the remaining 17.5 years, and this makes the wet type limestone-gypsum method more advantageous.

It should be noted that both Part II and Part III are likely to be operating for the next 20 to 30 years in consideration of Part III which started operation in 1981 and are the largest and latest power plant in Czechoslovakia, and Part II for which