DRY FLUE GAS DESULFURIZATION TECHNOLOGY EVALUATION

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PREPARED FOR

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PREPARED BY

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LEGAL NOTICE

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1. FLUE GAS DESULFURIZATION (FGD) DESCRIPTION

Lime-spray drying (LSD) is a dry scrubbing process that is generally used for low-sulfur coal. LSD FGD systems are typically located after the air preheaters, and the waste products are collected either in a baghouse or electrostatic precipitator. However, to achieve sulfer dioxide (SO_2) reduction above 80% with good reagent use, the dry scrubber is generally followed by a baghouse.

Flue gas is treated in an absorber by mixing the gas stream concurrently with atomized lime slurry droplets. The lime slurry is atomized through rotary cup spray atomizers or through dual fluid nozzles. Some of the water in the spray droplets evaporates, cooling the gas at the inlet from 300°C or higher to 160°F to 180°F, depending on the relationship between approach to saturation and removal efficiency. The droplets absorb SO_2 from the gas and react the SO_2 with the lime in the slurry. The desulfurized flue gas, along with reaction products, unreacted lime, and the fly ash passes out of the dry scrubber to the baghouse.

1.1 PROCESS CHEMISTRY

The SO_2 absorbed in the atomized slurry reacts with lime in the slurry to form calcium sulfite ($CaSO_3$) in the following reaction:

$$SO_2 + CaO + 1/2\ H_2O \Rightarrow CaSO_3 \bullet\ 1/2\ H_2O$$

A part of the $CaSO_3$ reacts with oxygen in the flue gas to form calcium sulfate ($CaSO_4$):

$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \Rightarrow CaSO_4 \bullet 2H_2O$$

1.2 REAGENTS AND WASTE PRODUCTS

Preparation of the lime slurry reagent involves slaking lime in a conventional lime slaker with a high efficiency grit removal and lime recovery system. The slaked lime is held in an agitated tank for use. The slurry reagent is fed to the absorber to replenish lime consumed in the reaction, and the feed rate is typically controlled based on the removal efficiency required.

The waste product contains $CaSO_3$, $CaSO_4$, calcium hydroxide, and ash.

1.3 COMMERCIAL STATUS

LSD FGD systems are in operation at many facilities, ranging in size from less than 10 MW to 500 MW (multiple modules are required for plants greater than 300 MW in capacity). For eastern bituminous coals, some FGD vendors have proposed modules for units sized up to 350 MW. Applications include commercial units with coal sulfur as high as 2.0%. LSD systems with rotary or dual fluid atomizers are available from a number of vendors including:

- Alstom Environmental Systems
- Babcock & Wilcox
- Hamon Research Cottrell
- Wheelabrator Air Pollution Control

2. DRY FGD PROCESS ADVANTAGES AND DISADVANTAGES COMPARED TO WET FGD TECHNOLOGY

2.1 PROCESS ADVANTAGES

The dry FGD process has the following advantages when compared to wet limestone FGD technology:

1. The absorber vessel can be constructed of unlined carbon steel, as opposed to lined carbon steel or solid alloy construction for wet FGD. Typically, for units less than 300 MW, the capital cost is lower than for wet FGD. Typically, for units larger than 300 MW, multiple module requirements causes the dry FGD process to be more expensive than the wet FGD process.

2. Pumping requirements and overall power consumption are lower than for wet FGD systems.

3. Waste $CaSO_3$, $CaSO_4$, and calcium hydroxide are produced in a dry form and can be handled with conventional pneumatic fly ash handling equipment.

4. The waste is stable for landfilling purposes and can be disposed of concurrently with fly ash.

5. The dry FGD system uses less equipment than does the wet FGD system, resulting in fixed, lower operations and maintenance (O&M) labor requirements.

6. The pressure drop across the absorber is typically lower than for wet FGD.

7. High chloride levels improve (up to a point), rather than hinder, SO_2 removal performance.

8. Sulfur trioxide (SO_3) in the vapor above approximately 300°F, which condenses to liquid sulfuric acid at a lower temperature (below acid dew point), is removed efficiently with a spray dryer-baghouse. Wet limestone scrubbers capture less than 25% to 40% of SO_3 and would require the addition of a wet electrostatic precipitator to remove the balance or hydrated lime injection. The emission of sulfuric acid mist, if above a threshold value, may result in a plume visible after the vapor plume dissipates.

9. Flue gas following a spray dryer is unsaturated with water (30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet limestone scrubbers produce flue gas that is saturated with water, which requires a gas-gas heat exchanger to reheat the flue gas to operate as dry stack. Due to the high costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operations.

10. Dry FGD systems have the capability of capturing a high percentage of gaseous mercury in the flue gas if the mercury is in the oxidized form. Further, due to the nature of the filter cake present in the fabric filter associated with LSD, the LSD equipment with a fabric filter will tend to capture a higher percentage of oxidized mercury than would LSD equipment with an electrostatic precipitator. The major constituent that will influence the oxidation level of mercury in the flue gas has been identified as chlorine. Considering the typical level of chlorine in coals in the United States, we can expect that LSD systems applied to high chlorine bituminous coals will tend to capture a high percentage of the mercury present in the flue gas. Conversely, LSD systems applied to low-chlorine sub-bituminous coals and lignite will not capture a significant amount of the mercury in the flue gas.

11. There is no liquid waste from a dry FGD system, while wet limestone systems produce a liquid waste stream. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant produces a small volume of waste, rich in toxic metals (including mercury) that must be disposed of in a landfill. A dry FGD system provides an outlet for process wastewater from other parts of the plant when processing residue for disposal.

2.2 PROCESS DISADVANTAGES

The dry FGD process has the following disadvantages when compared to limestone wet FGD technology:

1. The largest absorber module used in the industry is 250 MW to300 MW. Some suppliers of dry FGD systems have proposed absorbers as large as 350 MW for eastern bituminous coal-fired units. For units sized at 500 MW, two modules will be required. This will also result in large inlet and outlet ductwork and damper combinations.

2. The process uses a more expensive reagent (lime) than limestone-based FGD systems and the reagent has to be stored in a steel or concrete silo.

3. Reagent utilization is lower than for wet limestone systems to achieve comparable SO_2 removals. The lime stoichiometric ratio is higher than the limestone stoichiometric ratio (on the same basis) to achieve comparable SO_2 removals.

4. Dry FGD produces a large volume of waste, which does not have many uses due to its properties, i.e., permeability, soluble products, etc. Researchers may yet develop some applications where the dry FGD waste can be used. Wet FGD can produce commercial-grade gypsum.

5. Combined removal of fly ash and waste solids in the particulate collection system precludes commercial sale of fly ash if the unit is designed to remove FGD waste and fly ash together. In some cases, FGD could be backfit after the existing electrostatic precipitator, which would allow the sale of fly ash.

3. DESIGN BASIS

3.1 SPECIFIC DESIGN CRITERIA – DRY FGD

Table 3.1-1 lists the specific design criteria.

TABLE 3.1-1
SPECIFIC DESIGN CRITERIA

Unit capacity	500 MW	500 MW
Heat input to boiler, MBtu/hr	5,000	5,186
Fuel	Low-sulfur - Appalachian	Low-sulfur - Powder River Basin
Fuel analysis, % wt.:		
Moisture	6.0	30.4
Ash	9.1	6.4
Carbon	72.6	47.8
Hydrogen	4.8	3.4
Nitrogen	1.4	0.7
Sulfur	1.3	0.6
Oxygen	4.7	10.8
Chlorine	0.1	0.03
High heating value, Btu/lb	13,100	8,335
SO_2 generation, lb/Mbtu	2.0	1.44
Coal feed rate, tons/hr	191	311
Flue gas flow at FGD inlet, macfm	1.79	1.97
Flue gas temperature at FGD inlet, °F	280	280
Flue gas flow at FGD outlet, macfm	1.60	1.75
Flue gas temperature at FGD outlet, °F	160	165

TABLE 3.1-1 SPECIFIC DESIGN CRITERIA		
SO_2 reduction efficiency, %	94	93
SO_2 outlet, lb/MBtu	0.120	0.10
Mercury concentration in coal, ppmd	0.06-0.10	0.08-0.12

Table 3.1-2 summarizes the parameters used for the FGD comparison.

TABLE 3.1-2 PARAMETERS USED FOR FGD COMPARISON		
Unit Capacity	500 MW	500 MW
Heat input to boiler, MBtu/hr	5,000	5,186
Fuel	Low-sulfur - Appalachian	Low-sulfur - Powder River Basin
SO_2 removal, %	94	93
SO_2 emission, lb/MBtu	0.12	0.10
Byproduct	Dry waste	Dry waste
Power consumption, %	0.65 new (without baghouse), 1.1 for retrofit	0.70 new (without baghouse), 1.2 for retrofit
Reagent	High calcium lime	High calcium lime
Reagent cost, $/ton	60	60
Reagent purity, %	93	93
Reagent stoichiometry, moles of CaO/mole of inlet sulfur	1.4	1.1
Load factor	80	80
FGD system life, years	30 (new)/20 (retrofit)	30 (new)/20 (retrofit)
Capital cost leveling factor, %/year	14.5 (new)/15.43 (retrofit)	14.5 (new)/15.43 (retrofit)
Discount rate, %	8.75	8.75
Inflation rate, %	2.5	2.5
Operating cost levelization factor	1.30/1.22	1.30/1.22

3.2 SYSTEM DESIGN (SUBSYSTEMS)

The FGD system overall design consists of the following subsystems:

3.2.1 Reagent Handling and Preparation

Lime is received by truck (or barge) and conveyed to storage. Lime is stored in a 14-day capacity bulk storage lime silo. The lime is pneumatically conveyed to a 16-hour capacity day bin. The lime day bin and a gravimetric feeder supplies the lime to a 150% slaking system. This will allow two shift operations for the unit operating continuously at 100% load. A conventional lime slaker with high-efficiency grit removal and lime recovery system is used. Two 100% capacity slurry transfer pumps are used to provide high reliability to transfer the slurry to the slurry tank. The process makeup water is added to the slaker to produce 20% solids slurry. The slurry is diluted on line, if required, prior to injection into an absorber. The slurry is fed to the absorber by a dedicated reagent feed pump (100% spare capacity provided).

3.2.2 SO_2 Removal

Two absorbers, each treating 50% of the flue gas, are provided to achieve 93% to 94% SO_2 removal efficiency in the absorber and baghouse. The absorber is a vertical, open chamber with concurrent contact between the flue gas and lime slurry. The slurry is injected into the tower at the top using a rotary atomizer to remove SO_2. A spare rotary atomizer is provided. The hopper in the bottom of the carbon steel absorber also removes large particles that may drop in the absorber. The absorber will be operated at 30°F adiabatic approach to saturation temperature. In the past, a lower approach had been proposed. However, over the years, operational problems associated with the lower adiabatic approach to saturation temperature, due to wetting of the walls and large deposits in the absorber, were alleviated by designs with 30°F adiabatic approach to saturation temperature.

3.2.3 Baghouse

A pulse-jet baghouse with air to cloth ratio of 3.5 ft/min is provided. The baghouse is provided with a spare compartment for off line cleaning to maintain the opacity at 10% or less. The waste will be pneumatically conveyed to a waste storage silo with a 3-day storage capacity, which is in accordance with typical utility design.

3.2.4 Flue Gas System/Stack

The flue gas from the air preheater will be sent to the absorbers. The gases from the absorber will be sent to the baghouse to collect the waste products and the fly ash. The booster fan is sized to provide an additional 16”H_2O (12" w.c. operating) pressure drop through the absorber and baghouse. The existing stack will be used for the retrofit case.

3.2.5 Waste Handling

The waste will be collected in the baghouse. A portion of the waste will be stored in a recycle storage silo, which will then be used to mix with lime slurry to increase the reagent utilization. Pug mills (2 x 100%) are provided to treat the dry FGD waste before it is loaded onto the trucks for disposal or sale.

3.2.6 General Support

The general support equipment includes the seal water system, instrument air compressor, makeup water system, and control room.

3.2.7 Miscellaneous

Equipment considered as miscellaneous includes onsite electrical power equipment, such as transformers and grounding, which is required to supply electrical power to the FGD system.

Table 3.2–1 lists the equipment used in each subsystem.

TABLE 3.2-1 EQUIPMENT USED IN EACH SUBSYSTEM
Reagent Handling and Preparation
Truck unloading system
Lime bulk storage steel silo (14 days' storage)
Lime live storage transport
Lime day bin (16 hours' storage)
Slaker with screen (150% capacity)
Lime slurry tank (16 hours' storage)
Lime slurry feed pump (2 x 100%)
SO_2 Removal System
Spray dryer (2 x 50%)
Rotary atomizer (3 x 50% -2 operating and 1 spare)
Spray dryer solid conveying
Baghouse System
Pulse jet baghouse (air to cloth ratio – 3.5 ft/min)
Baghouse inlet ductwork
Baghouse outlet ductwork
Waste unloading system
Waste storage steel silo (3 days' storage)
Flue Gas System
Booster induced draft fans (2 x 50%)
Absorber inlet ductwork/dampers
Absorber outlet ductwork/dampers

TABLE 3.2-1 EQUIPMENT USED IN EACH SUBSYSTEM
Waste Handling and Recycle System
Recycle waste storage bin (16 hours' storage)
Recycle waste conveying
Recycle waste slurry tank
Pug mills (2 x 100%)
General Support System
Slaking water tank
Slaking water pumps (2 x 100%)
Instrumentation/plant air compressors (2 x 50%)
Miscellaneous
Transformers/switchgear
Electrical wiring, cables, etc.

4. IDENTIFICATION OF APPLICATION CONSTRAINTS

Summarized below are the application constraints that we have identified.

4.1 UNIT/ABSORBER SIZE

LSD FGD systems are in operation at many facilities, ranging in size from less than 10 MW to 500 MW. However, multiple modules are required for plants greater than 250 MW to300 MW in capacity.

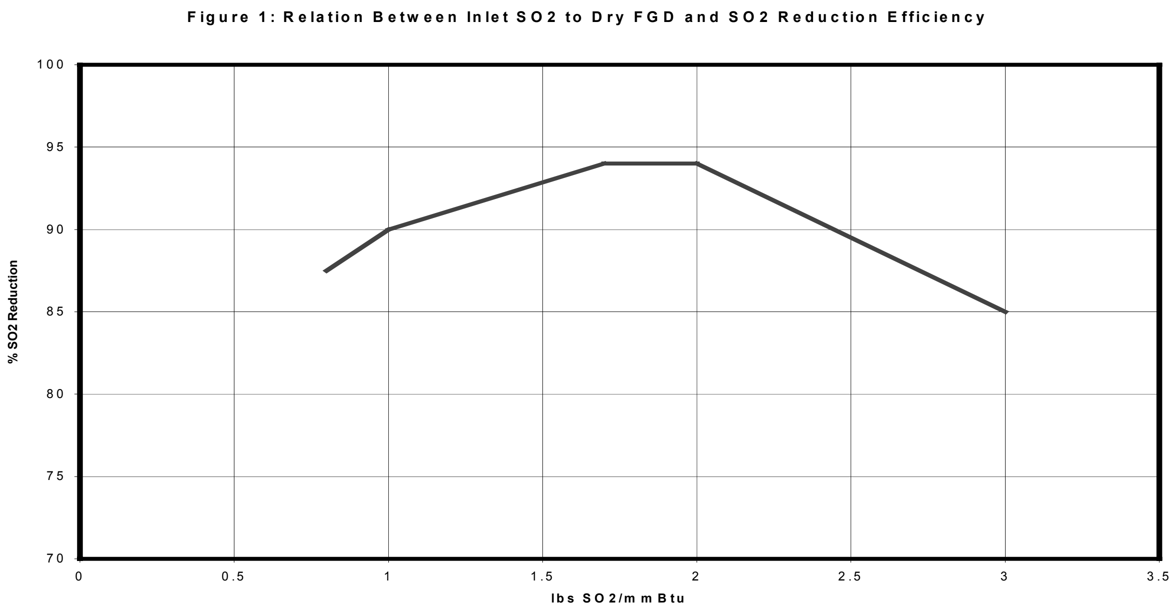
4.2 COAL SULFUR CONTENT

LSD FGD systems are applied mainly to low-sulfur coal. Most of these systems are applied to inlet SO_2 less than 2.0 lb/MBtu. These systems are based on Powder River Basin and western bituminous coal. The systems installed on low-sulfur eastern bituminous coal have SO_2 concentrations as high as 3.0 lb/MBtu. Sargent & Lundy's database of dry FGD systems indicates that these systems are not installed on high-sulfur bituminous coals.

4.3 PERFORMANCE EXPECTATIONS

The first generation of dry FGD systems was designed to achieve 70% SO_2 reduction efficiencies. This was done primarily to comply with the New Source Performance Standards (NSPS) for low-sulfur coals. However, further experience with Powder River Basin coal has prompted suppliers of dry FGD equipment to guarantee SO_2 reduction efficiencies up to 94% or 0.10 lb/MBtu, whichever is achieved first. Applying this recent experience to the FGD system described in Table3.1-1, with the inlet SO_2 from Powder River Basin fuel of 1.44 lb/MBtu, 94% reduction will result in an outlet emission of 0.086 lb/MBtu. This emission rate is less than 0.10 lb/Mbtu; hence, the SO_2 outlet of 0.10 lb/MBtu becomes the standard, which results in an overall SO_2 reduction efficiency of 93%. Figure 4.3-1 represents the maximum achievable SO_2 reduction for a dry FGD system with baghouse as it relates to the sulfur content in the coal. Figure 4.3-1 is derived from Sargent & Lundy's in-house database on the technology performance, as obtained from various suppliers of FGD systems.

FIGURE 4.3-1
RELATION BETWEEN INLET SO_2 TO DRY FGD AND SO_2 REDUCTION EFFICIENCY



4.4 SO_2 REDUCTION

Suppliers of FGD systems have guaranteed SO_2 reduction efficiencies up to 94% or 0.10 lb/MBtu, whichever is achieved first, with a dry scrubber- baghouse combination. This limits the inlet SO_2 level to 1.7 lb/MBtu. Suppliers of FGD systems were reluctant to provide Sargent & Lundy with higher removal guarantees, primarily due to the absence of any database.

4.5 REAGENT UTILIZATION

The reagent utilization is limited due to the mass transfer limitations. Suppliers of FGD systems are using alkalinity in the waste by recycling the waste along with the active reagent. The alkalinity of Powder River Basin ash has resulted in good reagent utilization compared to acidic fly ashes from eastern bituminous coal. For example, to achieve a reduction efficiency of 90% SO_2, a stoichiometric ratio of 1.1 could be used compared to 1.4 stoichiometric ratio for bituminous coals with waste recycling. The stoichiometric ratio for dry FGD is based on the inlet SO_2 concentration.

4.6 WASTE/BY-PRODUCT QUALITY

The waste product contains CaSO3, CaSO4, calcium hydroxide, and ash. This material cannot be used in the cement industry or wallboard; however, there is potential for use as agricultural soil conditioning and for preparation of bricks or aggregates by mixing with other waste components such as fly ash. If there is currently significant income from the sale of fly ash, it may be prudent to install the dry FGD/baghouse combination after the existing particulate collector, such that the fly ash is segregated from the LSD waste and can continue to be sold.

4.7 ENERGY CONSUMPTION

The major energy consumption is due to the pressure drop across the dry scrubber. Almost 60% to 70% of the energy required for FGD operation is due to an increase in draft (6-8" w.c., including inlet and outlet ductwork) and 25% to 35% of the energy required is for the atomizers.

4.8 RETROFIT VERSUS NEW UNITS

The LSD system is installed between the air heater outlet and particulate collector. Most existing units have very short ductwork between the air heater outlet and electrostatic precipitator inlet. This makes it very difficult to take the gas from the air heater outlet to the LSD equipment and return it to the electrostatic precipitator inlet. Also, most existing electrostatic precipitators are not designed to handle increased particulate loading resulting from the LSD waste products. This will require modifications to the existing electrostatic precipitator to accommodate collection of the additional particulate from the LSD. In addition, the electrostatic precipitator will capture only a small percentage of the SO_2 (5% to 10%), placing a high burden on the LSD for SO_2 removal. An added benefit of this LSD/FF combination is that the existing electrostatic precipitator can remain in service with the collected fly ash available for sale.

Considering these issues associated with using an existing electrostatic precipitator for particulate and SO_2 capture downstream of a retrofit LSD, employing a new fabric filter that can achieve 15% to 20% SO_2 capture and that can accommodate the LSD particulate loading, may be a more attractive alternative.

5. COSTS ANALYSIS

5.1 CAPITAL COSTS

Estimated capital costs for the dry FGD system were determined for new and retrofit applications, which includes the equipment, materials, structural, and electrical components associated with the retrofit installation of these technologies.

The costs were developed using Sargent & Lundy's database as well as price quotes obtained from manufacturers for the equipment/work needed.

The capital cost estimates provided herein are essentially "total plant cost," and include the following:

- Equipment and material
- Direct field labor
- Indirect field costs and engineering
- Contingency
- Owner's cost
- Allowance for funds during construction (AFUDC)
- Initial inventory and Spare parts (1% of the process capital)
- Startup and commissioning

Finally, the capital cost estimates provided do not include taxes and property tax. License fees and royalties are not expected for the proposed control strategies.

Salient features of each capital cost estimate prepared for FGD installations include:

- Demolition of existing ductwork to provide access to the flue gas from the air heater outlet
- Inlet and outlet ductwork to absorber and baghouse
- 2 x 50% absorbers
- Baghouse

- Induced draft fan modifications for retrofit application
- Auxiliary power system upgrade (for retrofit)

No range estimate was performed to assess the relative accuracy of this budgetary estimate. Based on experience, it is believed that the relative accuracy of the estimate is ±20%.

Additionally, the underlying assumption, unless specifically stated otherwise, is that the contracting arrangement for the project is large, multiple lump sum work packages. If the client expects to execute the project on an engineer, procure, construct or turnkey basis, a separate risk allocation should be added to the estimate of 5% to 20% (1.05 or 1.2 multiplier) for this method of construction, with actual value dependent on the relative risk of labor, construction difficulty, etc.

Exhibit 5–1 and Exhibit 5–2 present the capital costs for new units and retrofit units, respectively.

5.2 OPERATIONS AND MAINTENANCE COSTS

Exhibit 5–3 and Exhibit 5–4 present the estimated operations and maintenance (O&M) expenses associated with dry FGD systems. These costs include both fixed and variable operating costs, defined as follows:

5.2.1 Fixed O&M Costs

The fixed O&M costs determined for this study consist of sulfur oxides (SO_X) emission control technology, O&M labor, maintenance material, and administrative labor.

For purposes of this study, the installation of the FGD system has been anticipated to add an additional five operators to the current pool of operating labor for new units and eight operators for the retrofit application. It is assumed the plant layout for the retrofit application is not optimized, which would require more operating labor than for the new unit.

Maintenance material and labor costs shown herein have been estimated based on technology operating experience in the United States and Europe. The maintenance cost includes periodic replacement of atomizers and maintenance material for various subsystems, and the labor required to perform the maintenance.

5.2.2 Variable O&M Costs

Variable O&M costs determined for each technology include the cost of lime, waste disposal, bags and cages replacement, water, and power requirements. The cost of fly ash is not included in this study as it is assumed that even if the fly ash is currently disposed of or sold, the proposed configuration will not affect the current operation. For new unit operations, if the fly ash sale creates significant revenue, an electrostatic precipitator can be installed upstream of the dry FGD. This analysis assumes that the ash will be disposed of along with FGD waste for the new unit application and thus the only differential cost will be applicable to FGD waste.

No added penalty for lost production has been included due to forced downtime to maintain the FGD systems because the availability (measure of random outage rates) of FGD systems is expected to be greater than 99%.

Auxiliary power costs reflect the additional power requirements associated with the operation of the existing induced draft fans as well as the estimated power consumption for atomizers, compressor for baghouse, lime preparation system, and various electrical and control users typically needed for FGD operations. The owner will be responsible for the power cost of $30/MWH if the power is purchased from the open grid. This cost includes the replacement energy and capacity charges.

Exhibit 5–3 and Exhibit 5–4 present the fixed and variable O&M costs for new and retrofit applications, respectively.

5.3 LEVELIZED COSTS

Levelized costs, also referred to as “life cycle costs,” take into account the impacts of capital costs and O&M costs during the operation of a plant over the period of analysis. The levelized fixed charge rate (impact due to capital cost) was calculated based on an assumption that a typical customer is a regulated utility. The levelized fixed charge rate includes depreciation of the property, return on capital (50% debt and 50% equity), income tax, property tax, and insurance. Based on 8.75% discount rate and 30-year or 20-year life expectancy for new or retrofit facilities, respectively, the levelized fixed charge rates are 14.50% (30-year life) and 15.43% (20-years life). The levelized cost analysis was performed based on current dollars, as most regulated utilities base their analysis on current dollars.

The levelized O&M cost factor takes into account the discount rate, escalation rate, and annuity rate. The levelized O&M cost factors were 1.30 for the 30-year period and 1.22 for the 20-year analysis.

EXHIBIT 5-1

CAPITAL COST ESTIMATES FOR NEW UNITS USING PRB AND APPALACHIAN LOW SULFUR COALS

DRY FGD

	PRB Coal		Appalachian Low Sulfur	
Subsystems	**Cost, US$**	**$/kW**	**Cost, US$**	**$/kW**
Reagent Feed System	3,810,000	7.6	4,385,000	8.8
SO2 Removal System	11,700,000	23.4	11,400,000	22.8
Baghouse System	16,000,000	32.0	15,500,000	31.0
Flue Gas System	6,550,000	13.1	6,300,000	12.6
Waste Handling and recycle system	2,600,000	5.2	2,200,000	4.4
General Support Equipment	550,000	1.1	550,000	1.1
Miscellaneous Equipment	1,250,000	2.5	1,250,000	2.5
TOTAL PROCESS CAPITAL (TPC)	42,460,000	85	41,585,000	83
General Facilities (5% of TPC)	2,123,000	4.2	2,079,000	4.2
Engineering and Construction Management	4,246,000	8.5	4,159,000	8.3
Project Contingency (15%)	7,324,000	14.6	7,173,000	14.3
TOTAL PLANT COST (TPC)	56,153,000	112.3	54,996,000	110.0
Allowance for Funds (AFUDC - 3.2% of TPC)	1,797,000	3.6	1,760,000	3.5
Owner's Cost (5% of TPC)	2,808,000	6.0	2,750,000	5.0
TOTAL PLANT INVESTMENT (TPI)	60,758,000	121.9	59,506,000	118.5
Inventory Capital (Spare, 1% of TPI)	608,000	1.2	595,000	1.2
Initial Chemicals and Commissioning (2% of TPI)	1,215,000	2.4	1,190,000	2.4
Royalties	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR)	**62,581,000**	**126**	**61,291,000**	**122**

Notes:
1.0 Accuracy of Estimate +-20%
2.0 Labor cost based on regular shift operation
3.0 ID fan and electrical cost is differential

EXHIBIT 5-2

CAPITAL COST ESTIMATES FOR RETROFIT UNITS USING PRB AND APPALACHIAN LOW SULFUR COALS

DRY FGD

Subsystems	PRB Coal Cost, US$	PRB Coal $/kW	Appalachian Low Sulfur Cost, US$	Appalachian Low Sulfur $/kW
Reagent Feed System	4,645,000	9.3	5,338,000	10.7
SO2 Removal System	15,100,000	30.2	14,500,000	29.0
Baghouse System	19,000,000	38.0	17,000,000	34.0
Flue Gas System	8,690,000	17.4	8,350,000	16.7
Waste Handling and recycle system	3,400,000	6.8	2,800,000	5.6
General Support Equipment	550,000	1.1	550,000	1.1
Miscellaneous Equipment (Additional Transformer, Switchgear)	4,250,000	8.5	4,250,000	8.5
TOTAL PROCESS CAPITAL (TPC)	55,635,000	111	52,788,000	106
General Facilities (5% of TPC)	2,782,000	5.6	2,639,000	5.3
Engineering and Construction Management	5,564,000	11.1	5,279,000	10.6
Project Contingency (15%)	9,597,000	19.2	9,106,000	18.2
TOTAL PLANT COST (TPC)	73,578,000	147.2	69,812,000	139.6
Allowance for Funds (AFUDC - 3.2%)	2,354,000	4.7	2,233,984	4.5
Owner's Cost (5% of TPC)	3,679,000	7.0	3,491,000	7.0
TOTAL PLANT INVESTMENT (TPI)	79,611,000	158.9	75,536,984	151.1
Inventory Capital (Spare, same as new)	608,000	1.2	595,000	1.2
Initial Chemicals and Commissioning (same as new)	1,215,000	2.4	1,190,000	2.4
Royalties	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR)	**81,434,000**	**163**	**77,321,984**	**155**

Notes:
1.0 Accuracy of Estimate +-20%
2.0 Labor cost based on regular shift operation
3.0 ID fan and electrical cost is for adequate modifications to ID fan/motor, additional tranformers and switchgears
4.0 Medium Retrofit Difficulty assumed

EXHIBIT 5-3

FIXED AND VARIABLE O&M COST/LEVELIZED COSTS (NEW UNITS)

DRY FGD

Input for O&M Costs

		PRB	Eastern Low S
1	Number of Operators (40 hrs/wk)	5	5
2	Operating labor Cost, $/hr	50	50
3	Reagent Purity, %	93	93
4	Reagent Stoichiometry	1.1	1.4
5	Reagent Cost, $/ton	60	60
6	Reagent Requirement, t/h	3.22	6.59
7	SO2 Removal Efficiency, %	93	94
8	SO2 Removed, t/h	2.89	4.70
9	Waste Generated - dry, t/h (w/o fly ash)	7.01	12.74
10	Waste disposal cost, $/ton	12	12
11	Water Requirement, gpm	402	324
12	Water Cost, $/1000 gal	0.75	0.75
13	Bag Life, years	3	3
14	Bag Cost, $/bag	80	80
15	Cage Life, years	12	12
16	Cage Cost, $/cage	20	20
17	Aux. Power Requirement, MW	6.0	5.5
18	Aux. Power Cost, $/MWH	30	30
19	Load Factor, %	80	80

	PRB	Eastern Low Sulfur
Fixed O&M Costs		
1. Operating Labor Cost ($/yr)	$520,000	$520,000
2. Maintenance Materials Cost ($/yr)	$1,019,000	$998,000
3. Maintenance Labor Cost ($/yr)	$679,000	$665,000
4. Administrative and Support Labor =	$360,000	$356,000
Total Yearly Fixed O&M Cost =	$2,578,000	$2,539,000
Variable Operating Costs		
1. Reagent Costs =	$1,354,000	$2,769,000
2. Waste Disposal Cost for FGD System = (Dry basis)	$589,000	$1,071,000
3. Credit for Byproduct =	$0	$0
4. Bag replacement=	$375,000	$341,000
5. Cage replacement=	$23,000	$21,000
6. Water Cost=	$127,000	$102,000
7. Additional Power Costs* =	$1,261,000	$1,156,000
Total Yearly Variable O&M Cost =	3,729,000	5,460,000
TOTAL YEARLY FIXED AND VARIABLE O&M COS	6,307,000	7,999,000

* Includes the power requirement for reagent preparation and handling system, ID fan for 12" w.c. pressure drop, power for SO2 Control System (rotary atomizer), and power requirement for baghouse

Levelized Costs
Inputs for Levelized Costs

		PRB	Eastern Low S
1	FGD System Life, years	30	30
2	Capital Cost Levelization Factor	14.5	14.5
3	Discount rate, %/yr	8.75	8.75
4	Inflation Rate, %	2.5	2.5
5	Operating Cost Levelization Factor	1.30	1.30
	Total Capital Cost, M$	62.6	61.3
	Levelized capital Cost, MM$/yr	**9.07**	**8.89**
	Levelized O&M Cost, MM$/yr	**8.20**	**10.40**
	Total Levelized Cost, MM$/yr	**17.27**	**19.29**
	Total cents/kW-hr	**0.49**	**0.55**

EXHIBIT 5-4

FIXED AND VARIABLE O&M COST/LEVELIZED COSTS (RETROFIT UNITS)

DRY FGD

Input for O&M Costs

		PRB	Eastern Low S
1	Number of Operators (40 hrs/wk)	8	8
2	Operating labor Cost, $/hr	50	50
3	Reagent Purity, %	93	93
4	Reagent Stoichiometry	1.1	1.4
5	Reagent Cost, $/ton	60	60
6	Reagent Requirement, t/h	3.22	6.59
7	SO2 Removal Efficiency, %	93	94
8	SO2 Removed, t/h	2.89	4.70
9	Waste Generated - dry, t/h (w/o fly ash)	7.01	12.74
10	Waste disposal cost, $/ton	12	12
11	Water Requirement, gpm	402	324
12	Water Cost, $/1000 gal	0.75	0.75
13	Bag Life, years	3	3
14	Bag Cost, $/bag	80	80
15	Cage Life, years	12	12
16	Cage Cost, $/cage	20	20
17	Aux. Power Requirement, MW	6.0	5.5
18	Aux. Power Cost, $/MWH	30	30
19	Load Factor, %	80	80

	PRB	Eastern Low Sulfur
Fixed O&M Costs		
1. Operating Labor Cost ($/yr)	$832,000	$832,000
2. Maintenance Materials Cost ($/yr)	$1,019,000	$998,000
3. Maintenance Labor Cost ($/yr)	$679,000	$665,000
4. Administrative and Support Labor =	$453,000	$449,000
Total Yearly Fixed O&M Cost =	$2,983,000	$2,944,000
Variable Operating Costs		
1. Reagent Costs =	$1,354,000	$2,769,000
2. Waste Disposal Cost for FGD System = (Dry basis)	$589,000	$1,071,000
3. Credit for Byproduct =	$0	$0
4. Bag replacement=	$375,000	$341,000
5. Cage replacement=	$23,000	$21,000
6. Water Cost=	$127,000	$102,000
7. Additional Power Costs* =	$1,261,000	$1,156,000
Total Yearly Variable O&M Cost =	3,729,000	5,460,000
TOTAL YEARLY FIXED AND VARIABLE O&M COS	6,712,000	8,404,000

* Includes the power requirement for reagent preparation and handling system, ID fan for 12" w.c. pressure drop, power for SO2 Control System (rotary atomizer), and power requirement for baghouse

Levelized Costs
Inputs for Levelized Costs

		PRB	Eastern Low S
1	FGD System Life, years	20	20
2	Capital Cost Levelization Factor	15.43	15.43
3	Discount rate, %/yr	8.75	8.75
4	Inflation Rate, %	2.5	2.5
5	Operating Cost Levelization Factor	1.22	1.22
	Total Capital Cost, M$	81.4	77.3
	Levelized capital Cost, MM$/yr	**12.57**	**11.93**
	Levelized O&M Cost, MM$/yr	**8.19**	**10.25**
	Total Levelized Cost, MM$/yr	**20.75**	**22.18**
	Total cents/kW-hr	**0.59**	**0.63**