BRITISH COLUMBIA HYDRO & POWER AUTHORITY
HAT CREEK PROJECT
FLUE GAS DESULFURIZATION STUDY

Ebasco Services Incorporated
Two Rector Street
May 1977

604H. E005

B.C. HYDRO & POWER AUTHORITY
HAT CREEK PROJECT
2000 MW (Net) Plant

12 May, 1977

I. MCS ANALYSIS INPUT DATA (Per ERT's Request of 22 April, 1977 - ERT Doc. No. P-5074,652)

1. PHYSICAL STACK PARAMETERS

Stack Height (1200 feet)

Outside Shell Diameter (66 feet)

Flue Size - Inside Diameter (23 feet)

2. FUEL CHARACTERISTICS (Calculated at 20% Moisture)

	$\tilde{X}$
Primary Fuel Sulfur Content $\tilde{X}$	0.45%
Secondary Fuel Sulfur Content	0.21%
Primary Fuel Heat Value	6300 BTU/lb
Secondary Fuel Heat Value	7564 BTU/lb
Primary Fuel Ash Content	26%
Secondary Fuel Ash Content	19.15%

3. EMISSION CHARACTERISTICS (Per Each Boiler Unit)

Flue Gas Temperature with Mean Primary Fuel 300^{o}F

Flue Gas Temperature with Mean Secondary Fuel 300^{o}F

Flue Gas Volume Flow Rate with Mean Primary Fuel 2.195×10^{6} ACFM

SO_2 Emission Rate with Mean Primary Fuel 7442 lbs/hr

Flue Gas Volume Flow Rate with Mean Secondary Fuel 2.103×10^{6} ACFM

SO_2 Emission Rate with Mean Secondary Fuel 3473 lbs/hr

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II FGD Analysis Input Data Required by ERT
(per ERT's request of 22 April, 1977 - ERT Doc. No. P-5074-652)

Fuel		Case I	Case II
Primary Fuel Sulphur Content, $\bar{X}$ %		0.45	0.45
Plant Fuel Preparation		Blending	Blending
Heating Value	Btu/lb.	6300	6300
Moisture	%	20	20
Ash	%	26	26

Scrubber Design Data

Number of Scrubbers/Unit		2 + 1 spare	3 + 1 spare
Unit Distribution		2 + 1 spare	3 + 1 spare
Degree of Scrubbing		Partial	Full
Type		SO_2 removal	SO_2 removal
Efficiency	%	90	86

Operating Characteristics

Removal Efficiency			
Tower	%	90	86
Overall	%	48.4	86

Availability: With provision of one spare SO_2 absorber for each unit overall FGD system availability is expected to be equal to or exceed availability of the associated steam generator.

Flue Gas Flow Rate		Case I	Case II
a) Entering scrubbers	lbs/hr.	3.540	5.935×10^6
@ 30% excess air	ACFM	1.309×10^6	2.195×10^6
b) By-pass flow	lbs/hr.	2.395×10^6	---
	ACFM	0.886×10^6	---
Flue Gas Temperature Entering Scrubbers	^oF	300	300
Saturated Gas Temperature	^oF	114	114
Flue Gas Reheat		By mixing with by-pass	By mixing with heated AMB air
Stack Exit Temp.	^oF	180	170
Moisture picked up in Scrubber	lbs/hr.	141,000	263,000
Flue Gas Flow Rate,	lbs/hr.	6.076×10^6	8.325×10^6
Leaving Stack	ACFM	2.313×10^6	3.25×10^6
Stack Exit Velocity	FPS	90	90 (126 if the same flue dia is used as in Case I)
SO_2 Generation	lbs/hr.	7442	7442
SO_2 Quantity Discharged by Stack After Scrubbing	lbs/hr.	3443	1042
Stack SO_2 Emission (by vol. dry @ 3% O_2)	PPM	300	91
Startup/shutdown SO_2 Emission	PPM	0	0
SO_2 Removal Efficiency			
a) Overall Efficiency	%	54%	86%
b) Tower Efficiency	%	90%	86%

<u>Economics and Energy Consumption</u>
(Total for four units)

		Case I	Case II
Total Investment Cost for four (4) FGD systems, including escalation to scheduled startup dates	$1000	252,540	362,270
Electric Power Consumption	KW	5,430	12,180
Limestone Consumption	lbs/hr.	7,500	15,300
Lime (Fixative) Consumption	lbs/hr.	240	500

	Case I	Case II
Makeup Water Requirements, GPM	235	535
Flue Gas Reheater Steam Consumption $\frac{lbs.}{hr.}$	0	146,000
Annual Owning and Operating Costs ($1000/yr.)		
a) Fixed Charge on Investment @ 13.78% F.C. Rate	34,800	49,920
b) Capacity & Replacement Energy Charge	6,040	13,550
c) Steam Consumption	0	5,320
d) Reagent Consumption (Limestone for scrubbers and lime additive for sludge fixation)	1,540	3,000
e) Operating Labour Cost	3,070	3,840
f) Maintenance Material & Labour	7,580	10,800
Total Owning & Operating Cost (Summation of a through f)	53,030	86,430
Total Capitalized Owning and Operating Cost for Four (4) FGD Systems (Capitalized @ .1378 Factor) $1000	384,833	627,213

Sludge Disposal

Above investment and operating costs include the necessary equipment, materials and operating and maintenance labour associated with the sludge removal and disposal to the landfill area near the plant site.

The waste disposal system in both cases includes equipment to mechanically dewater the thickener underflow and then to mix it with dry fly ash and lime. The resulting mixture will be disposed of as an environmentally safe, structurally sound landfill.

The thickener underflow will be pumped to a vacuum filter for additional dewatering. The vacuum filter will further dewater the scrubber solids to 50-55 percent solids. At this consistency the material will be a thick slurry which would not be suitable for direct use as a landfill.

In order to solidify the vacuum filter cake, a part of dry fly ash from the precipitators will be mixed with the filter cake at a predetermined ratio. The resulting mixture would contain about 70 percent solids and would have a plastic consistency.

In order to produce a solid material either a quick lime or hydrated lime will be added simultaneously with fly ash. Depending on the reactivity of the fly ash between 0.5 to 2.0 percent lime will be required.

After mixing, the material will be transported by trucks to a disposal site where it will be allowed to harden.

The mixture will begin to harden after 48 hours and will have a considerable strength after seven days of curing.

The total area required for fixed sludge disposal from four (4) units, generated during their 35 years life and average life capacity of 65%, is estimated as follows:

300 acres @ 20 ft. high pile for Case I
600 acres @ 20 ft. high pile for Case II

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2. DISCUSSION (Cont'd)

EXHIBITS

1. SUMMARY

1.1 Purpose

The study developes conceptual design and estimated investment and operating costs for two alternative flue gas desulfurization systems for the Hat Creek Project. The quality of coal supplied to the plant and the chimney emission levels differ for the two alternatives.

A state-of-the-art review of the status of flue gas desulfurization is also included.

1.2 Scope

The two Plans selected for study are as follows:

Plan 1 This Plan assumes use of a blended coal with an allowable SO_2 emission level of 300 ppm (dry) by volume. Treatment of a portion of the flue gas is required.

Plan 2 This Plan assumes use of an unblended coal with an allowable SO_2 emission level of 170 ppm (dry) by volume. All of the flue gas is treated.

The coal characteristics for the two Plans are as follows:

	Plan 1	Plan 2
Sulfur - %	0.45	0.90
Heating Value - Btu/lb	6300	5500
Moisture - %	20	20
Ash - %	26	32

The design parameters include the number of absorber modules, SO_2 removal efficiency, reagent, steam and power requirements and tonnage of waste products. System and process description of each Plan is provided.

The economic considerations include respective investment costs and capitalized owning and operating costs of the two Plans considered.

The investment cost estimates include the material and erection for all equipment and ductwork between the ID fan outlet and the stack breeching.

The components of the capitalized annual owning and operating cost are as follows: fixed charges on investment, capacity and replacement energy charges, steam, reagent, operating and maintenance costs.

1.3 Results

1.3.1 Technical Evaluation

The following Table summarizes the major system design parameters presented in the Technical Summary Exhibit 1, and Material Balance Exhibit No. 4.

	Technical Summary per Boiler	
	Plan No. 1	Plan No. 2
Boiler Size (MW) Net, Nominal	500	500
Total Heat Input (10^6 x Btu/hr)@ MCR	5 464	5 464
Coal Firing Rate (lb/hr)	867 301	993 455
Plant Elevation (ft ASL)	4 600	4 600
Gas Flow Rate (lb/hr)	6 400 000	6 534 000
Inlet SO_2 (lb/hr)	7 838	17 955
Outlet SO_2 (lb/hr)	4 048	2 604
Emission Stack (PPMD)	300	170
Inlet Gas Temperature FGD (F)	300	300
Saturated Gas Temperature (F)	114	122
Stack Exit Temperature (F)	203	170
Reagent Limestone Purity (%)	90	90
Stoichiometry (%)	115	115
Design Coal Sulfur (%)	0.45	0.90
Heating Value (Btu/lb)	6 300	5 500
Ash Content (%)	26	32
Type of FGD System	Wet	Wet
SO_2 Absorber Tower (No.)	2 + 1 Spare	3 + 1 Spare
FGD Scrubbing	Partial	Full
Flue Gas Treated (lb/hr)	3 436 800	6 534 000

	Technical Summary per Boiler Plan No. 1	Plan No. 2
Flue Gas Bypassed (lb/hr)	2 963 200	0
Liquid to Gas (L/G)	80	80
SO_2 Removal Efficiency		
a) Overall Efficiency (%)	48.35	85.49
b) Tower Efficiency (%)	90.02	85.49
System Pressure Drop (in./H_2O)	9	9
Limestone Consumption (lb/hr)	7 558	30 622
Lime Consumption (Fixative)(lb/hr)	236	956
Ash Consumption (Fixative)(lb/hr)	5 903	23 958
Makeup Water (GPM)	235	535
Disposal Cake Blended (TPH)	12.92	50.85
Flue Gas Reheater Steam Requirement (lb/hr)	0	146 007
Power Consumption (kW)	5 434	12 186
Pond Size (35 yr @ 20 ft)(acres)	75	298
Stack Liner Diameter (@ 90 FPS Velocity)(ft)	23	27

1.3.2 Investment

Tabulated below are comparable investment estimates for material and erection of vendor and owner supplied material and erection, including escalation as detailed in Exhibit No. 6.

	Comparable Investment ($1000 US) Plan 1	Plan 2	Differential
Unit 1	72 110	101 900	29 790
Unit 2	56 150	81 030	24 880
Unit 3	59 900	86 430	26 530
Unit 4	64 380	92 910	28 530
Total	252 540	362 270	109 730

1.3.3 Capitalized Annual Owning & Operating Cost

The comparable capitalized annual owning and operating cost for each Plan design considered is detailed in Exhibit No. 7 and summarized below:

Capitalized Owning & Operating Cost (US $1000)

Item	Plan No. 1 Total 4 Units	Plan No. 2 Total 4 Units
1) Fixed Charge on Investment	34 799	49 920
2) Capacity & Replacement Energy Charge	6 044	13 548
3) Steam Consumption	0	5 320
4) Reagent Consumption		
a. Limestone	1 384	5 584
b. Lime Additive	152	612
5) Operating Labor Cost	3 072	3 840
6) Maintenance Material & Labor	7 575	10 867
7) Total Annual Owning & Operating Cost	53 026	89 691
Differential	Base	36 665
8) Capitalized Owning & Operating Cost	384 803	650 879
Differential	Base	266 076

2. DISCUSSION

2.1 General

Conceptual designs were prepared for the two alternative Plans. The designs were based on flue gas treatment systems which consist of an electrostatic precipitator for particulate removal and an absorber for sulfur dioxide removal. Limestone was used as the reagent. The systems were based on disposal of the effluent to an adjacent storage area.

There are a number of other type systems which are in various stages of development. No attempt was made to evaluate the different systems. The conceptual designs were based on the precipitator/absorber combination as this is the most common arrangement in use in the United States today. However, if a decision is made to install a FGD system then a detailed study of all alternatives should be made. It is possible that in the near future some other system may become more economic than the one included in the study.

2.2 Design Factors

The design factors used in this study are summarized in the Table below:

		Plan No. 1	Plan No. 2
1)	Boiler Size (MW)	500	500
2)	Total Heat Input (Btu/hr)	5464×10^6	5464×10^6
3)	Coal Firing Rate (lb/hr)	867 301	993 455
4)	Plant Elevation (ft, ASL)	4600	4600
5)	Barometric Pressure (psia)	14.36	14.36
6)	Total Gas to System (lb/hr)	6 400 000	6 534 000
7)	Inlet SO_2 lb/hr	7838	17 955
8)	Outlet SO_2 (a) lb/hr	4048	2604
	(b) PPMD	300	170
9)	Inlet Gas Temperature, F	310	310
10)	Stack Exit Temperature	203	170
11)	Reagent: Limestone Purity, %	90	90
12)	FGD Scrubbing	Partial	Full
13)	Fuel Type:	Typical Blended	Worst Acceptable Not Blended
	Proximate Analysis:		
	% Moisture	20	20
	% Ash	26	32
	% Volatile	26	23.84
	% Fixed Carbon	28	24.16
	Btu/lb	6300	5500
	Sulfur	0.45	0.90
	Ultimate Analysis (Dry) Includes Undetermined Error		
	% Carbon	47.50	40.82*
	% Hydrogen	3.75	3.53
	% Nitrogen	1.13	0.90
	% Chlorine	0.04	0.03
	% Sulfur	0.56	1.13
	% Ash	32.50	40.10
	% Oxygen**	14.53	15.80

*Calculated

**Oxygen by determination not by difference

2.3 System & Process Description

2.3.1 Summary Description

The process development for the two Plans is similar except for the percentage of flue gas treated for SO_2 removal and the method of reheating. Plan 1 treats 55 percent of the flue gas and utilizes bypass gas for reheating. Plan 2 treats 100 percent of the gas and uses hot air for reheating.

The process scheme for the proposed Flue Gas Desulfurization System (FGD) is presented for the maximum load condition on Process Flow Diagram Exhibits No. 8 & 9, and Material Balance on Exhibit No. 4. The system follows high efficiency electrostatic precipitators for flyash removal, and utilizes absorbers for sulfur dioxide removal. The FGD System has been designed to function as an independent system and will not affect the operation of the boiler unit.

The flue gas initially enters the gas cleaning system downstream of the electrostatic precipitators and the boiler ID fans which provide the energy required to draft the boiler and to deliver the gases through the FGD system. Depending on the selection of equipment, additional booster fans may be required in series with the ID fans. The fans discharge into the operating absorbers where the required amount of sulfur dioxide is removed utilizing a reactant slurry of pulverized limestone. Following the pass through the absorber mist eliminators, the temperature of the clean flue gas is raised by the injection of ambient air which is reheated in indirect steam-air exchangers (only for Plan 2). The reheated gases then enter the stack.

The proposed system includes bypass ducts immediately preceding the absorbers. Periodic maintenance on the non-operating module can be conducted at any time without adversely affecting the particulate collection or the performance of the FGDS. The bypass also allows circumvention of of the entire FGDS in the event the system becomes inoperable or during periods when low sulfur coal is burned and SO_2 removal is not required.

The pulverized limestone slurry is produced and continuously fed into the sulfur dioxide absorption system by wet ball mills and associated slurry preparation equipment. The spent calcium slurry from the absorption system is continuously discharged to a thickener. The concentrated thickener underflow discharges into the waste sludge treatment system for ultimate disposal. Water from the thickener is returned for use in the limestone system.

The thickener underflow slurry is pumped to a vacuum filter for additional dewatering. The resulting filter cake is a thick slurry but is not suitable for direct use as landfill. In order to further solidify the vacuum filter cake, it is mixed with dry flyash from the precipitators and with either quick lime or hydrated lime, depending on the reactivity of the flyash. Between 0.5 and 2.0 percent lime will be required. After mixing the material is transported to a disposal site, where it will be allowed to harden.

Two operating modules plus one spare are required for Plan No. 1, and three operating modules plus one spare are required for Plan No. 2.

2.3.2 Flue Gas Absorber

Sulfur dioxide removal from the flue gas takes place in the absorber. The absorber design will be based on one of a number of proven high efficiency absorbers, such as open spray or packed bed towers. The design will depend on the final process selection. Each absorber will be equipped with a mist eliminator to prevent mist carry-over to downstream equipment and ductwork. A spare absorber is provided. The maximum pressure drop attributable to flow losses through the absorbers is expected to be on the order of 8 to 9 inches of water, including ductwork.

In the event a spray tower is used, each tower will be 43 ft diameter and 65 ft high for Plan No. 1 and 50 ft diameter and 65 ft high for Plan No. 2. Materials of construction will be carbon steel with corrosion proof lining.

2.3.3 Recycle Tank (Reaction Tank)

The absorbing slurry is discharged from the absorber and gravity fed to the recycle tank. The recycle tank retains the slurry for a predetermined period of time in a state of agitation.

Retention, mixing (agitation) and oxidation, permit the de-supersaturation and crystallization of calcium salts in the recycle tank. The successful accomplishment of this assures that the spent solids can be removed and makeup slurry can be introduced for further absorption. A bleed stream of spent reaction products is continuously withdrawn from the recycle tank and pumped to the thickener system. Makeup alkali slurry and water are continuously added to this tank in order to maintain the pH and solids concentration of the slurry at predetermined levels. The recirculation pumps withdraw the recycle slurry from the bottom of the tank and recirculate it to the absorber.

A 43 ft diameter by 24 ft high tank for Plan No. 1, and a 50 ft diameter by 24 ft high tank for Plan No. 2 with corrosion proof lining will be required for each absorber. Four (4) motor (25 hp) operated mixers will be included with the tank. Normally two (2) mixers will be operating, while two (2) will remain as spare.

2.3.4 Waste Slurry Handling & Water Reclaimation

The spent recycle slurry, bled from the recycle tanks, is collected into a waste slurry tank which is constantly agitated. In addition, the overflow from the mist eliminator wash tank is also collected in the waste slurry tank. The waste slurry is mixed with a poly-electrolytic flocculant, as it is pumped to the thickener. The thickener allows the precipitated calcium salts to settle by means of gravity. The settled calcium salts (thickener underflow) then are pumped to a vacuum filter for further solids concentration (60 weight percent solids). The water reclaimed from both the thickener and vacuum filtration is returned into the FGD system for reuse.

2.3.5 Waste Slurry Sump Tanks

One (1) waste slurry sump tank will be required for each absorber to receive bleed flows from the individual absorbers. A motor (10 hp) operated mixer will be included with each tank.

2.3.6 Waste Slurry Storage Tank

One (1) waste slurry storage tank per steam generator will be required to receive waste slurry flows from each absorber waste slurry sump tank. Each tank will be sized for one hour holding time.

2.3.7 Reagent Slurry Tank (Alkali Storage Tank)

One (1) reagent slurry tank, with an 8-hour slurry storage capacity, will be required for each unit. The tank will have a corrosion proof lining and will be equipped with two (2) motor (40 hp) operated mixers.

2.3.8 Mill Slurry Sump Tanks

One tank per ball mill, concrete rectangular construction, sized according to the recirculation rate, will be required for the ball mill classifiers.

2.3.9 Wash Water Tanks (Reclaimed Water Tanks)

One wash water tank per steam generator will be required to provide for recycling of water from the mist eliminator wash trays, located in the top section of the absorber towers. Size of tanks will depend on the specific manufacturer's system design.

2.3.10 Limestone Preparation System

The limestone preparation system is designed to produce the limestone slurry required for continuous operation of the system under the worst coal conditions. Volumetric feeders continuously feed the limestone to a crusher and ball mill which, through mechanical action and water introduction, will produce a given weight slurry. The transfer of slurry to each of the recycle tanks is accomplished by pumps which respond to changing SO_2 and load conditions via pH monitor of recycle slurry.

2.3.11 Limestone Live Silos (Alkali Silo)

Two (2) silos, each capable of storing a 16 hour supply of limestone, will be required to serve one steam generating unit. One (1) will feed active ball mills and one will serve as a standby.

2.3.12 Alkali Feeder

Two (2) gravimetric type weight feeders, each capable of handling the limestone supply for one (1) steam generating unit; one (1) will feed active balls mills and one will serve as a standby.

2.3.13 Ball Mills

One (1) wet, single compartment ball mill, capable of handling the limestone supply for one (1) steam generating unit, will be required to serve one (1) unit. Mills will be sized to meet the stone requirement. Spare mills are provided. Design limestone feed size is 100 percent minus 3/4 inches. Final size is 80 percent minus 200 mesh. One (1) wet cyclone classifier will classify wet limestone slurry from each ball mill. Plan No. 1 will require a 3.8 TPH ball mill and Plan No. 2 will require a 15.33 TPH ball mill capacity.

2.3.14 Emergency Quench Pump

Each steam generating unit will have an emergency water pump conviently located to provide for hot flue gas cooling in the event of a power outage of the station or an air heater malfunction.

2.3.15 Flue Gas Reheater

For Plan No. 2, one (1) central reheat system will be required to raise the temperature of the flue gas exiting the absorbers by approximately 50 F. The reheat system will be based on an indirect steam coil/hot air design using 146 007 lb/hr of extraction steam at about 200 psi and 650 F.

Ambient air (2 336 114 lb/hr) will be heated and mixed with the wet gas exiting the operating absorbers. The steam coils, 2 ambient air fans and associated ductwork, will be carbon steel construction. Thermostatic controls will regulate steam and air flows to maintain 50 F temperature rise for the wet gas.

2.3.16 Absorber Inlet Ductwork & Absorber Bypass

Ductwork, including flue gas distribution devices, access manholes, instrument and test connections and expansion joints, will be provided for flue gas flow from the air heater outlet to the absorber inlets and for the absorber bypass. The material of construction for all ductwork included within this scope will be unlined carbon steel.

2.3.17 Absorber Outlet Ductwork

Ductwork, including flue gas distribution devices, access manholes, instrument and test connections, and expansion joints, will be provided for flue gas flow from the outlet of the absorbers to the stack inlet. The material of construction for all ductwork included within this scope will be carbon steel with a corrosion proof lining capable of withstanding continuous operation at 350 F.

2.3.18 Mixing Chamber

The mixing chamber will be located downstream from the absorber. The bypassed gas is then mixed with the treated gas in the mixing chamber for reheating, for Plan No. 1 and for Plan No. 2 ambient air will be heated and mixed with the wet gas exiting the operating absorber.

2.3.19 Pipe

Piping of a suitable corrosion and erosion resistant design will be specified for the transfer of reagent and waste slurry within the FGD system limits. Rubber lined steel and fiber glass reinforced polyester "FRP" pipe will be required.

2.3.20 ID Booster Fans

Two (2) parallel booster fans, may be required to deliver the flue gases to the absorber. Each will be capable of handling 50 percent of the steam generator flue gas at 100 percent load. The fan margin will be 20 percent on capacity and 44 percent on head.

2.3.21 Pumps

The pumps listed below will be required. The preliminary number and related horsepower is shown in Exhibit No. 3. The absorber recycle and absorber quench pumps will operate continuously while the remaining pumps will operate intermittently (on-off). Water flushing provisions will be required for intermittent pumps handling slurry to prevent settling in the system.

- Sulfur Dioxide Absorber Recycle Pumps
- Absorber Quench Recycle Pumps
- Wash Water Pumps
- Reagent Slurry Feed Pumps
- Mill Classifier Pumps
- Waste Slurry Pond Transfer Pump
- Emergency Quench Pump
- Waste Slurry Sump Pumps

2.3.22 Limestone Handling System

2.3.22.1 General

For Plan No. 1 7558 lb/hr limestone is required per each steam generating unit.

For Plan No. 2 30 622 lb/hr limestone is required per each steam generating unit.

2.3.22.2 Storage Capacity

The system will be designed for thirty (30) days storage capacity for each unit at 100 percent capacity factor. The storage capacity will be 2720 tons of limestone for Plan No. 1 and 11 038 tons for Plan No. 2.

2.3.22.3 Limestone Handling Equipment

The limestone handling system will include reclaim hopper, a belt conveyor system for delivery to a future crusher (if required) for direct delivery to either the day silos or to the 30 day storage silos.

2.3.23 Waste Disposal System

The waste disposal system will provide equipment to mechanically dewater the thickener underflow and then mix it with dry flyash and lime. The resulting mixture will be disposed of as an environmentally safe, structurally sound landfill.

The waste disposal system will start with thickener underflow containing 25 to 30 percent solids. From the thickener the slurry will be pumped to a vacuum filter for additional dewatering. The vacuum filter will further dewater the scrubber solids to 50 to 55 percent solids. At this consistency, the material will be a thick slurry which would not be suitable for direct use as landfill.

In order to solidify the vacuum filter cake, a part of dry fly-ash from the precipitators will be mixed with the filter cake at a pre-determined ratio. The resulting mixture would contain about 70 percent solids and would have a plastic consistency. In order to produce a solid material either quick lime or hydrated lime will be added simultaneously with the flyash. Depending on the reactivity of the flyash between 0.5 to 2.0 percent lime will be required.

After mixing, the material will be transported by trucks to a disposal site, where it will be allowed to harden. The mixture will begin to harden after 48 hours and will have considerable strength after seven (7) days of curing.

The required disposal area for Plan No. 1 is 75 acres for each unit, and for Plan No. 2 is 298 acres for each unit (35 yr @ 20 ft).

2.3.24 FGD Dampers

The following dampers will be required:

Location	Type
System Inlet & Outlet	Isolation
Absorber Inlet	Isolation
Absorber Outlet	Isolation
Absorber Bypass	Isolation
Booster Fan Inlet	Isolation
Booster Fan Outlet	Isolation
Reheat Fan Inlet	Isolation
Reheat Fan Outlet	Isolation
Absorber Outlet	Flow Control
Absorber Bypass	Flow Control

The isolation dampers will be of the guillotine type design and will be capable of achieving zero leakage. The flow control dampers will be of the louver type design.

2.3.25 Chimney Liner

Liner will be provided for the concrete chimney. The liner will be designed for dry operating mode conditions and the liner will be corrosion proof with a coating capable of withstanding continuous operation at 350 F.

For Plan No. 1 a 23 ft diameter liner is required.

For Plan No. 2 a 27 ft diameter liner is required.

2.4 PRESSURE LOSSES

There are various pressure losses associated with the flow of flue gas through the air quality control system. The pressure drop through the precipitator, including its connecting ductwork, may be expected to be approximately 4.5 inches of H_2O. This, together with the loss through the convective passes of the steam generator approximately 7 inches of H_2O and the drop through the secondary air heater approximately 7 inches of H_2O define the static pressure at the inlet of the first pair of induced draft fans.

The second set of fans (booster fans) will handle the draft loss of the flue gas desulfurization system approximately 8 to 9 H_2O, including ductwork, an additional 1 inch of H_2O will result from the air heater and stack. The basic systems considered are shown diagramatically on Exhibit No. 12 for Plan No. 1 and Exhibit No. 13 for Plan No. 2.

2.5 ECONOMIC EVALUATION

The economic evaluation factors used in this study are summarized in the Table below:

	Each Unit	
	Plan No. 1	Plan No. 2
Boiler Size (MW)	500	500
Total Heat Input (Btu/hr)	5464×10^6	5464×10^6
Net Station Heat Rate (Btu/kWh)	10 679	10 679
Heating Value of Coal (Btu/lb)	6 300	5 500
Coal Firing Rate (lb/hr)	867 301	993 455
Average Annual Capacity Factor (%)	65	65
Coal Cost (1976)	$5.60/T	$5.60/T
Capacity & Replacement Energy Charge (20 Mills/kWh Power Cost including the Capital Component) at 100% Capacity Factor Levelized ($/kW)	428	428
Average Levelized Reagent Cost		
$CaCO_3$ ($/ton)	16	16
CaCO ($/ton)	56	56
Average Levelized Steam Cost ($/lb)	0.0016	0.0016
Fixed Charges (%)	13.78	13.78
Operating Life (Years)	35	35

Inflation Rate Used:

Fiscal Year	Rate	Rate
1976-1977	Base	Base
1977-1978	11	11
1978-1979	9	9
1979-1980	8	8
1980-1981	7	7
1981-1982	5	5
Thereafter	5	5
Levelization Factor	2.443	2.443

Order-of-magnitude investment and operating cost estimates have been made for each of the two Plans considered in this study.

2.5.1 Scope of Equipment

The scope of each investment estimate includes the FGD equipment supplied by the vendor and the FGD System and equipment that the owner will have to provide, including the following:

- Limestone handling and storage
- Booster fans
- Waste fixation facilities, such as ash bins and lime bins and mixer
- Pond, including land
- Conveyors
- Trucks
- Bulldozer
- Foundations
- Electrical, including large motors, wiring, etc

On the gas side, the general limits may be identified as the ID fan outlet to the stack main duct as shown on Exhibit No. 10 for Plan No. 1 and Exhibit No. 11 for Plan No. 2. On the liquid side, all piping, valves and controls associated with reagent, water makeup and waste flows are within the battery limits of the evaluation.

2.5.2 Investment

The escalated investment costs for the vendor and for the owner supplied equipment, including materials and erection are shown in Exhibit No. 6 and are summarized below:

Comparable Investment ($1000 US)

	Plan No. 1	Plan No. 2	Differential
Unit 1	72 110	101 900	29 790
Unit 2	56 150	81 030	24 880
Unit 3	59 900	86 430	26 530
Unit 4	64 380	92 910	28 530
Total	252 540	362 270	109 730

The material and erection costs for vendor supplied equipment represent a composite estimate based on budgetary proposals received from FGD System vendors. The materials and erection costs of the owner supplied equipment are estimated by Ebasco based on the best available information. They are subject to change upon receipt of more detailed data.

The estimates are made on the total construction cost level and include escalation to the operating date.

2.5.3 Capitalized Annual Owning & Operating Cost

The following items are included in the annual owning and operating cost analysis: fixed charges, capacity and replacement energy charges, steam and maintenance, operating and reagent cost.

A capacity factor of 65 percent was assumed. A rate of 13.78 percent was used in calculating the Fixed Charge on Investment.

The total capitalized owning and operating costs are shown in detail in Exhibit No. 7 and are summarized below:

Capitalized Owning & Operating Cost (US $1000)

Item	Plan No. 1 Total 4 Units	Plan No. 2 Total 4 Units
1) Fixed Charge on Investment	34 799	49 920
2) Capacity & Replacement Energy Charge	6 044	13 548
3) Steam Consumption	0	5 320
4) Reagent Consumption		
a. Limestone	1 384	5 584
b. Lime Additive	152	612
5) Operating Labor Cost	3 072	3 840
6) Maintenance Material & Labor	7 575	10 867
7) Total Annual Owning & Operating Cost	53 026	89 691
Differential	Base	36 665
8) Capitalized Owning & Operating Cost	384 803	650 879
Differential	Base	266 076

2.5.4 Schedule

A proposed schedule for engineering, procurement, and erection of the FGD system is given in diagram form on Exhibit No. 5 for one unit (500 MW). This schedule is generally in accordance with Ebasco's experience on similar size units and indicates that the system can be ready for operation 34 months after receipt of an order. This schedule is based on a 20 month erection period, contingent upon owner's completion of all foundations 14 months after award of contract.

2.6 THE STATUS OF FLUE GAS DESULFURIZATION & COMMENTS ON RELIABILITY

2.6.1 The Status of Flue Gas Desulfurization

Four processes, all using wet scrubbers, have gained varying degrees of user acceptance in the United States. These are as follows:

1) Wet limestone/lime scrubbing
2) Alkali scrubbing without regeneration (Single Alkali Process)
3) Alkali scrubbing with alkali regeneration (Double Alkali Process)
4) Alkali scrubbing with regeneration

The first three processes listed are throwaway types and the latter one is a recovery type for which the first demonstration on coal is in the initial stages of operation at Northern Indiana Public Service Co's Mitchell plant. Two recovery processes, catalytic oxidation (Cat-Ox-Process) and magnesium oxide scrubbing were at one time considered promising, but Cat-Ox is no longer under active consideration in the U S or elsewhere, and two out of three MgO demonstrations are shutdown.

In addition, two other recovery processes are in the prototype stage of development on utility boilers in the United States. These are the Chiyoda Thoroughbred 101 process (partial recovery), and the Foster-Wheeler-Bergbau Forschung process. Several other recovery processes are in the pilot-plant stage of development in the United States. These include the Shell-UOP Copper Oxide process, the Consol process, the U S Bureau of Mines Citrate process, the Stauffer Phosphate process, the Stone and Webster/Ionics process, the Westvaco process, and several processes based on ammonia scrubbing.

Exhibit No. 14 shows the full-scale and demonstration plants that have operated or were to begin operation in 1976 on boilers in the United States to remove SO_2. So far, about 30 desulfurization units have been installed serving a capacity of about 6000 MW, another 25 are under construction, and about 50 are planned in utility plants producing a total of about 45 000 MW for all existing and planned installations. This is out of a total fossil fueled capacity of 325 000 MW.

2.6.1.1 Throwaway Processes

Limestone or lime absorption which produces a calcium sulfite/sulfate sludge for waste disposal has been the most prevalent system selected by the utilities in the United States. This process can be operated either by injecting limestone into the boiler followed by wet scrubbing to capture the SO_2 and particulates or tail-end limestone absorption. The single alkali and double alkali processes are two other types of throwaway processes in commercial use. The double alkali process has been developed to combine the best features of limestone/lime absorption and the single alkali process. Sodium alkali (clear liquor) is used to absorb SO_2 to prevent plugging and scaling in the absorber, and the absorber effluent is reacted with limestone and/or lime to precipitate calcium sulfite and sulfate for waste disposal.

2.6.1.2 Limestone Injection-Wet Scrubbing

Exhibit No. 14 includes the limestone injection-wet absorption installations in the United States. Meramec was the first system and it was abandoned because of plugging in the boiler tubes. The 125 MW system at Lawrence started up in 1968, and the 400 MW system in 1971. After many modifications, the unit is still experiencing problems. Scaling problems in the absorber have made it necessary to reduce limestone feed to the boiler at the expense of lower SO_2 removal efficiencies. The units are kept in operation by nightly cleanup of half the absorbers which are taken off line when the system is at a reduced load. Kansas Power & Light is revising both systems at Lawrence to tail-end limestone absorption. Of the two limestone injection units at the Hawthorn Station, one has been converted to injecting limestone after the air heater rather than into the boiler. Combustion Engineering no longer offers boiler injection of limestone as an SO_2 control system.

2.6.1.3 Tail-End Limestone Absorption

Exhibit No. 14 includes the tail-end limestone scrubbing installations in the United States.

The Will County Station of Commonwealth Edison is the first tail-end limestone scrubbing system in the United States. It started up in February 1972. It is a Babcock & Wilcox system which uses venturi scrubbers backed up by a sieve plate column or a turbulent contact absorber. The venturi scrubber is used for particulate control and the absorber is used for SO_2 control.

The major non-mechanical problems at Will County have been plugging of the mist eliminators and corrosion of the reheater tubes. Also, waste disposal is an unsolved problem. During the first two years of operation, availability of the more reliable module, the one with the sieve plate absorber, was 25 percent. In the spring of 1974, monthly availability for this module ranged from 55 to 96 percent, and in late 1974 and throughout most of 1975, the monthly availability consistently remained about 90 percent. The improved performance was attributed to use of lower sulfur coal, lower gas velocity, addition of a second-stage mist eliminator, fresh-water mist eliminator underspray, and a 30 gpm blowdown stream to the ash pond which allowed the fresh water underspray. Both modules are now in service.

The LaCygne plant has the largest limestone scrubber in the United States. It is on an 800 MW boiler burning coal with 5.5 percent sulfur and 25 percent ash and uses a Babcock & Wilcox system very similar to Will County. Startup occurred in June 1973, and the initial availability was about 45 percent because of maintenance and cleanup requirements. Lately, improved maintenance procedures and design modifications have led to improved availability. The SO_2 removal is about 80 percent. There are 7 modules to handle the gas flow from the boiler and each module is cleaned once every 7 days during the night shift. There has been reheater tube corrosion so that the reheat is now supplied by hot air taken from the combustion preheater. This causes a 160 MW loss in power generation because of the capacity of the forced draft and induced draft fans. The system is operated with a closed loop with a 160 acre pond for waste disposal. This company is now building a second large generating unit at LaCygne but it will use low sulfur coal.

The Cholla installation is on a 115 MW boiler fired with low sulfur coal (0.5 percent sulfur) and was started up in December, 1973. The availability of the two modules of this system has been very high, 85 percent for one and 93 percent for the other. This system uses a flooded disc scrubber for particulate control followed by an absorption tower with rigid packing for SO_2 control. The SO_2 removal is greater than 90 percent. Sludge is sent to an existing ash pond where the water in-flow is lost by evaporation. There is no recycle stream from the ash pond back to the scrubber system. The main problems with the Cholla system have been reheater tube vibration and corrosion of expansion joints and reheater tubes. A second Cholla system is scheduled to start up in June 1978.

In the last several years a number of additional systems have gone into service.

2.6.1.4 Tail-End Scrubbing with Lime

Exhibit No. 14 also lists the lime scrubbing installations in the United States. Paddy's Run is probably the most successful FGD installation to date in the United States. It is on a 65 MW boiler burning 3.7 percent sulfur coal and the reactant is byproduct $Ca(OH)_2$, a waste residue from acetylene manufacturer. "Mountains" of this carbide lime are available adjacent to the Paddy's Run power plant as a result of acetylene manufacturer at an adjacent chemical plant. The Paddy's Run system started up in April, 1973 and through December, 1973 the availability was 90 percent. The unit is only a peaking unit and except for 1973 is run only about two months during the year. However, Louisville Gas & Electric is satisfied with the operation of this demonstration unit and has ordered two more carbide lime scrubbing systems for their large boilers.

The largest lime scrubber is the 880 Chemico installation which cost over $130 million and which started up in June 1975 at the new Mansfield plant run by Pennsylvania Power Company for the CAPCO group of utilities.

2.6.1.5 Double Alkali Process

One way to avoid the sodium salt disposal problem is to react the scrubber effluent with limestone and/or lime to precipitate calcium sulfite and sulfate and recirculate sodium alkali back to the scrubber. This is called the double alkali process and the installations in the United States are listed in Exhibit No. 14. The General Motors facility in Ohio is on four industrial boilers equivalent to about 32 MW burning 2 to 3 percent sulfur coal. This system started up in March 1974. The SO_2 is scrubbed with sodium alkali solution and the scrubber effluent is reacted with lime. The sludge is filtered and dumped into a sanitary landfill. The problem is that it is difficult to regenerate sodium sulfate because it does not react well with lime. The boilers are operated with high excess air so that there is up to 80 percent oxidation resulting in poor lime utilization. However, the SO_2 removal is 85-90 percent.

Two other double alkali installations are in operation on industrial boilers in the United States. Also, a double alkali installation has recently operated at the Scholz plant of Gulf Power at 20 MW level.

2.6.1.6 Recovery Processes

The recovery or regenerable FGD process types, many of them relatively recent, offer the following advantages over throw-away processes: (1) no sludge or filter cake to dispose of, (2) regeneration of SO_2 sulfur, or H_2SO_4 as a saleable by-product and (3) significantly reduced quantities of secondary waste streams. The improved advantages of regenerable processes are gained at a price. The price involves two components: (1) a generally higher investment and operating cost compared to the throwaway FGD process types, and (2) increased energy input if a reducing gas is required for sulfur production (up to 5 percent of the energy input to the boiler). Exhibit No. 15 shows the status of regenerable systems in the U S. Only few installations have been tried on coal and most of these have been shutdown because of discouraging cost projections and other problems.

2.6.2 Comments on Reliability

Having spent these considerable sums of investment and operation, the utilities must examine what has actually been purchased in terms of reliability.

The prime purpose of the FGD is of course to remove sulfur dioxide. Essentially, all systems currently in operation achieve their design efficiencies of 70 to 90 percent SO_2 removal. This aspect has never been a serious concern with the major problem being one of reliable long-term operation. The basic problem areas have been corrosion, erosion and scaling, and it is instructive to examine some of the directions that have been taken on corrective action.

Scrubbing liquors can be low in pH and high in chlorides and are generally incompatible with metals for carbon steel components. Significant progress has been made with lining of equipment with sheet rubber and trowel-on types of corrosion-resistant coatings. Moderate success has been achieved by moving up into alloys which are high in nickel and chrome. This extends useful life, but at a substantially higher cost.

This has caused a reassessment of the way the components are put together into the system. In most current designs, the ID fans are put upstream of the absorber rather than downstream, and reheaters are located outside the system rather than in-line. This approach is one of changing the environment to fit the equipment, and it represents a big step back into the more comfortable realm of plain carbon steel metallurgy.

Significant progress has also been achieved in the area of slurry abrasion by going very soft or very hard with rubber or ceramics. Ceramic spray nozzles and high capacity rubber lined pumps have been developed which perform quite well. Bad experience on controlling slurry flows has generally led to the conclusion that the best valve is no valve at all. Systems are now set up for off-on operation with no modulation of slurry flow and valves are no longer a problem.

Progress on scaling and plugging problems has been limited. Handling of slurries is quite different than pumping clear water and a more widespread appreciation of this difference has led to better initial layouts of the pumps and piping in the system. There is a current trend toward the open spray tower type of absorbers with no internal packing built in to promote gas/liquid contacting. Open spray towers, therefore, represent a class of equipment with a minimal amount of internal hardware which could be sensitive to the effects of scaling. However, the demisters must remain in the system at the absorber outlet and this component has emerged as the major problem area. One solution that has been quite successful involves inclusion of a wash tray ahead of the demister. The function of the wash tray is to dilute the solids concentration of the entrained slurry and thus reducing the scaling/plugging potential in the demister area.

Minimizing scaling by close control of system chemistry is an approach which is receiving a lot of discussion today. However, an absorber is a very crude chemical reactor, and there are many external constraints imposed on the system by the overall material balance. It is possible, therefore, to control and adjust system chemistry only within limited ranges. Continued efforts along several aspects of the chemistry modification concept will most certainly provide some answers on the how and why of scale formation. However, it remains to be seen if it will lead to the development of universal solutions.

The reliability of full scale FGD systems is improving but many problems remain and none has yet demonstrated, on high sulfur coal, a level of reliability equivalent to other major power plant components.

The problem is to be able to provide the demister and/or wash tray enough wash water while still operating the system in a closed-loop mode. The amount of makeup water is limited to the amount of water that goes up the stack as vapor due to evaporative cooling of the flue gas and the amount of water that leaves with the sludge.

Another problem is stack gas reheating. It is considered desirable to reheat the stack gas from its adiabatic saturation temperature of about 125 F to a temperature of about 150 to 175 F where the relative humidity of the stack gas would be about 50 percent. Reheat helps to improve plume bouyancy and prevents rainout around the stack. In most installations, reheat has been accomplished by placing the steam coils directly in the path of the flue gas. This method is prone to result in corrosion of the tubes and pluggage. To avoid this problem, external exchangers have been employed to heat ambient air which is then injected into the flue gas. However, this method is more expensive in operating costs than direct in-line reheater tubes. Fuel oil fired burners have also been used for reheat, but the shortage of petroleum products makes this option unattractive.

Another problem is sludge disposal for throwaway FGD systems. In some locations, ponding has been used and in other locations landfill has been used. The long-term environmental effects of sludge disposal have not been resolved at any location.

Also, the availability of limestone and lime may be a problem for throwaway FGD systems if they are applied on a widespread basis. For recovery FGD systems, there is the problem of marketing by-product sulfuric acid or sulfur. While sulfur is easy to store, as was mentioned before, its production requires a reducing agent which is generally not available at power plants.

Overall FGD system availability has generally not been good. Although there are many instances of sustained periods of operation with availabilities greater than 90 percent, there are still far too many cases of units operating at 50 percent availability for several months at a time. Considering the number of hard problems on FGD systems which have been solved, we might expect that an upward trend in availability is occurring. Such a trend cannot be shown at this time, not necessarily because it does not exist, but rather because it has only been with the last year that statistical data collection has started on a comprehensive basis. Many FGD units now going into operation are equipped with a bypass in anticipation of limited emission variances. It is hoped that regulatory agencies will realize that although SO_2 removal is possible, it may never be possible 100 percent of the time.

A V Stack concluded recently:

"It is evident from the foregoing that much progress has been made in flue gas desulfurization and that a conventional lime-limestone scrubbing technology is emerging. The main remaining problem is entrainment separation; although acceptable operation has been attained in some systems, this is still a troublesome area in which further development is needed.

Much more work is also needed both in process optimization and in developing a design base that will make it possible to design with confidence for site-specific factors. Although reliability has been improved lack of confidence by designers still makes a spare scrubber the usual choice for assuring non-interference with boiler operation."

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO
HAT CREEK PROJECT
FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

1.	SYSTEM AND PERFORMANCE		PLAN NO. 1	PLAN NO. 2
1.1	No. of Modules (operating + spare)		2 + 1	3 + 1
1.2	Type of Absorber		Vertical - Spray	Vertical - Spray
1.3	Flue Gas Flow Rate	Lb/Hr	6 400 000	6 534 000
1.4	Flue Gas To Be Treated	Lb/Hr	3 436 800	6 534 000
1.5	Flue Gas To Be Bypassed	Lb/Hr	2 963 200	0
1.6	SO_2 Removal Efficiency		-	-
	a. overall efficiency	Percent	48.35	85.49
	b. tower (absorber) efficiency	Percent	90.02	85.49
1.7	Total Power Installed	kW	7 135	14 571
1.8	Total Power Consumption	kW	5 434	12 186
1.9	System Pressure Drop	Inch H_2O	9	9
1.10	Limestone Consumption	Lb/Hr	7 558	30 622
1.11	Lime (Fixative) Consumption	Lb/Hr	236	956
1.12	Ash (Fixative) Consumption	Lb/Hr	5 903	23 958
1.13	Makeup Water	Gpm	235	535
1.14	Flue Gas Reheater Steam Consumption	Lb/Hr	0	146 007
1.15	Inlet Absorber Gas Temperature	$^\circ F$	300	300
1.16	Outlet Absorber Saturated Gas Temperature	$^\circ F$	114	122
1.17	Stack Exit Temperature	$^\circ F$	203	170
1.18	Stack Exit Velocity	Fps	90	90
1.19	Stack Liner 1. Diameter	Ft	23	27
1.20	Ambient Air for Flue Gas Reheat	Lb/Hr	0	2 336 117
1.21	Stack Exit Gas Flow Rate	Lb/Hr	6 555 478	9 149 792
1.22	Pond Size (.35 Yr @ 20 Ft & 65% CF)	Acres	75	298
1.23	L/G	Gal/1000 ACFM	80	80
1.24	Stoichiometry	Percent	115	115
1.25	Reagent Purity	Percent	90	90

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO

HAT CREEK PROJECT

FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

2.	EQUIPMENT (MAJOR)		PLAN NO. 1	PLAN NO. 2
2.1	Absorber (SI)			
2.1.1	No. of Absorbers (operating + spare)		2 + 1	3 + 1
2.1.2	No. of Stages		2	3
2.1.3	Dimensions Diameter/Height	Ft	43/65	50/65
2.1.4	Casing Material/Thickness	Inch	A36/¼"	A36/¼"
2.1.5	Lining Material		NEOPREN	NEOPREN
2.1.6	Internal Piping		-	-
	- slurry material		HAST. C	HAST. C
	- clear water material		FRP	FRP
2.1.7	Nozzles		-	-
	- slurry material		Silicon - Carbide	Silicon Carbide
	- clear water material		Carpenter 20	Carpenter 20
2.1.8	Water Tray Type/Material		Hat/Trough/FRP	Hat/Trough/FRP
2.1.9	Demister Type/Material		2 Stage Chevron/FRP	2 Stage Chevron/FRP
2.2	Tanks			
2.2.1	Recycle Tank (TI)		-	-
2.2.1.1	No. per Absorber/Total Boiler		1/3	1/4
2.2.1.2	Material/Thickness Inch		A36 - 1/3	A36 - 1/4
2.2.1.3	Lining Material		Flak Lining	Flak Lining
2.2.1.4	Dimensions Diameter/Height	Ft	43/24	50/24
2.2.1.5	No. of Agitators per Tank and Brake	Hp	(2 + 1) x 100	(3 + 1) x 100
2.2.1.6	Agitator Material		Rubber Covered	Rubber Covered

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO
HAT CREEK PROJECT
FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

2.	EQUIPMENT (MAJOR) (Cont'd)		PLAN NO. 1	PLAN NO. 2
2.2.2	Mist Eliminator Tank (T2)		-	-
2.2.2.1	No. Per System		1	1
2.2.2.2	Material		A36	A36
2.2.3	Waste Slurry Tank (T3)		-	-
2.2.3.1	No. Per System		1	1
2.2.3.2	Material		A36	A36
2.2.3.3	Lining		Flak Lining	Flak Lining
2.2.3.4	No. of Agitators and Brake Hp		1 x 50	1 x 50
2.2.3.5	Agitator Material		Rubber Covered	Rubber Covered
2.2.4	Alkali Storage Tank (T4)			
2.2.4.1	No. Per System & Dimensions	Ft	1 x 15' Dia x 15' Height	1 x 25' Dia x 15' Height
2.2.4.2	Material		A36 Rubber Lined	A36 Rubber Lined
2.2.4.3	No. of Agitators and Brake Horsepower		1 x 50	1 x 50
2.2.4.4	Agitator Material		Rubber Covered	Rubber Covered
2.2.5	Reclaim Water Tank (T6)		-	-
2.2.5.1	No. Per System		1	1
2.2.5.2	Material		A36 Flak Lined	A36 Flak Lined
2.2.6	Thickner Tank (T7)		-	-
2.2.6.1	No. Per System		1	1
2.6.6.2	Dimensions Dia/Height		100/20	60/20
2.2.6.3	Material		A36	A36
2.2.6.4	Rack Brake Horsepower		50	50
2.3	Pumps			
2.3.1	Absorber Recycle Pumps (P1)		-	-
2.3.1.1	No. Operating/Spare/Per Boiler		8/4/12	12/4/16
2.3.1.2	Brake Horsepower/Pump	Hp	395	516
2.3.1.3	Lining		Nat. Rubber	Nat. Rubber

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO

HAT CREEK PROJECT

FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

2.	EQUIPMENT (MAJOR) (Cont'd)		PLAN NO. 1	PLAN NO. 2
2.3.2	Mist Eliminator Pump (P2)		-	-
2.3.2.1	No. Operating/Spare/Per Boiler		1/1/2	1/1/2
2.3.2.2	Brake Horsepower/Pump	Hp	152	365
2.3.2.3	Lining		Rubber	Rubber
2.3.3	Waste Slurry Pump (P3)		-	-
2.3.3.1	No. Operating/Spare/Per Boiler		1/1	1/1
2.3.3.2	Brake Horsepower/Pump	Hp	5	5
2.3.3.3	Lining		Rubber	Rubber
2.3.4	Makeup Slurry Pump (P4)		-	-
2.3.4.1	No. Operating/Spare/Per Boiler		1/1/2	1/1/2
2.3.4.2	Brake Horse power/Pump	Hp	5	5
2.3.4.3	Lining		Rubber	Rubber
2.3.5	Reclaim Water Pump (P6)		-	-
2.3.5.1	No. Operating/Spare/Per Boiler		1/1/2	1/1/2
2.3.5.2	Brake Horsepower/Pump	Hp	30	30
2.3.5.3	Lining		Rubber	Rubber
2.3.6	Thickener Underflow Pump (P7)		-	-
2.3.6.1	No. Operating/Spare/Per Boiler		1/1/2	1/1/2
2.3.6.2	Brake Horsepower/Pump	Hp	5	5
2.3.6.3	Lining		Rubber	Rubber
2.4	Feeder (M5)			
2.4.1	Type		Gravimetric Weight Feeder	Gravimetric Weight Feeder
2.4.2	No. Operating/Spare/Per Boiler		1/1/2	1/1/2
2.4.3	Brake Horsepower/Feeder	Hp	10	20

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO
HAT CREEK PROJECT
FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

2.	EQUIPMENT (MAJOR) (Cont'd)		PLAN NO. 1	PLAN NO. 2
2.5	Ball Mills (M8)			
2.5.1	No. Operating/Spare/Per Boiler		1/1/2	1/1/2
2.5.2	Type		Wet Single Compartment	Wet Single Compartment
2.5.3	Mill Capacity	TPH	3.8	15.33
2.5.4	Brake Horsepower/Mill		100	200
2.6	Vacuum Filter (M10)			
2.6.1	No. Operating/Spare/Per Boiler		1/1/2	3/1/4
2.6.2	Type		Door Oliver	Door Oliver
2.6.3	Brake Horsepower/Filter	Hp	100	150
2.6.4	Vacuum Filter Pump Total No./Hp		(2 + 1) 50	(6 + 2) 50
2.6.5	Filter Pump		(1 + 1) 10	(3 + 1) 15
2.7	Mixer (Fixation Facility)			
2.7.1	No. Operating/Sprare/Per Boiler		1/1/2	2/1/3
2.7.2	Brake Horsepower/Mixer		120	175
2.8	Flue Gas Reheater			
2.8.1	No. Operating		-	One Central System
2.8.2	Type			Steam Coil Hot Air Injection
2.8.3	Steam			200 Psi and 650° F
2.8.4	Steam Consumption	Lb/Hr		146 007
2.8.5	Material			Corten
2.8.6	Δ Temperature	$^\circ$ F		50
2.8.7	Air Fan			
2.8.7.1	No. Operating			2
2.8.7.2	Ambient Air Rate	Lb/Hr		233 114
2.8.7.3	Brake Horsepower	Hp		2 x 1 400

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO
HAT CREEK PROJECT
FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

2.	EQUIPMENT (MAJOR) (Cont'd)		PLAN NO. 1	PLAN NO. 2
2.9	ID Booster Fans			
2.9.1	No. Operating		2 x 50% MCR	2 x 50% MCR
2.9.2	Type		Axial	Axial
2.9.3	Brake Horsepower	Hp	2 x 1 500	2 x 2 450
2.10	Dampers*			
2.10.1	Isolation Type Dampers		ANDCO (Metroflex)	ANDCO (Metroflex)
2.10.1.1	System Inlet & Outlet	No. Oper	1 + 1	1 + 1
2.10.1.2	Absorber Inlet & Outlet	No. Oper	3 + 3	4 + 4
2.10.1.3	Absorber Bypass	No. Oper	1	1
2.10.1.4	Booster Fan Inlet & Outlet	No. Oper	2 + 2	2 + 2
2.10.1.5	Reheat Fan Inlet & Outlet	No. Oper	0	2 + 2
2.10.2	Flow Control Damper		ANDCO	ANDCO
2.10.2.1	Absorber Outlet	No. Oper	2 + 1	3 + 1
2.10.2.2	Absorber Bypass	No. Oper	1	1
2.11	Silos and Bins			
2.11.1	Limestone 30 Day Storage Silo & Material		Concrete Closed	Concrete Closed
2.11.1.1	Capacity for 30 Day	Tons	2 720	11 038
2.11.1.2	No. Operating	#	1	1.25
2.11.1.3	Dimensions	Diameter/Hight Ft	36/65	55/100
2.11.2.	Limestone Live Silo			
2.11.2.1	No. Operating/Spare/Total per Price		1/1/2	1/1/2
2.11.2.2	Material and Thickness	Inch	A36/1/4"	A36/1/4"
2.11.2.3	Capacity (Storing @ 16 HR) Each	Tons	60	245

* Each damper with 5 hp drive motor and air seal drive motor.

TECHNICAL SUMMARY

BRITISH COLUMBIA HYDRO
HAT CREEK PROJECT
FGD SYSTEM FOR 500 MW (EACH BOILER) FULL LOAD

2.	EQUIPMENT (MAJOR) (Cont'd)		PLAN NO. 1	PLAN NO. 2
2.12	Bins			
2.12.1	Lime (Fixative) Bin			
2.12.1.1	No. Operating		1	1
2.12.1.2	Material and Thickness	Inch	A36/1/4"	A36/1/4"
2.12.1.3	Capacity	Day/Tons	3	11.5
2.12.2	Ash (Fixative) Bin			
2.12.2.1	No. Operating		1	1
2.12.2.2	Material and Thickness	Inch	A36/1/4"	A36/1/4"
2.12.2.3	Capacity	Day/Tons	71	288
3.	TRUCKS (FOR LIMESTONE AND WASTE CAKE TRUCKINGS)			
3.1	No. Operating/Spare/Total per Boiler		2/1/3	8/2/10
3.2	Type		Dumper	Dumper
3.3	Capacity	Ton	50	50
4.	BULLDOZER			
4.1	No. Operating/Spare/Total per Boiler		1/1/2	2/1/3
4.2	Type		Caterpillar	Caterpillar
4.3	Capacity	Cubic Yds		
5.	POND			
5.1	Size (35 Yr @ 20 Ft @ 65% CF)	Acres	75	298

BC Hydro
Hat Creek Project - 500 MW

EXHIBIT NO. 2
Sheet 1 of 2

FGD MAJOR EQUIPMENT LIST PER BOILER

		Plan No. 1			Plan No. 2		
		Operating	Spare	Total	Operating	Spare	Total
1.	Scrubber (SO_2 Absorber)	2	1	3	3	1	4
2.	Reheater Coils	0	0	0	2	0	2
3.	Reheater Fans	0	0	0	2	0	2
4.	Recycle Tanks	2	1	3	3	1	4
5.	Mist Eliminator Tank	1	0	1	1	0	1
6.	Waste Slurry Tank	1	0	1	1	0	1
7.	Alkali Storage Tank	1	0	1	1	0	1
8.	Reclaimed Water Tank	1	0	1	1	0	1
9.	Thickener Tank	1	0	1	1	0	1
10.	Recycle Pumps	8	4	12	12	4	16
11.	Mist Eliminator Pumps	1	1	2	1	1	2
12.	Waste Slurry Pumps	1	1	2	1	1	2
13.	Makeup Slurry Pumps	1	1	2	1	1	2
14.	Reclaimed Water Pumps	1	1	2	1	1	2
15.	Thickener Pumps	1	1	2	1	1	2
16.	Recycle Agitators	2	1	3	3	1	4
17.	Waste Slurry Agitator	1	0	1	1	0	1
18.	Alkali Storage Agitator	1	0	1	1	0	1
19.	Limestone Silo (16 hr)	1	1	2	1	1	2
20.	Limestone Feeder	1	1	2	1	1	2
21.	Ball Mill	1	1	2	1	1	2
22.	Vacuum Filter	1	1	2	3	1	4
23.	Ash Bin (Fixation)	1	0	1	1	0	1
24.	CaO Bin (Fixation)	1	0	1	1	0	1
25.	Mixer (Fixation)	1	1	2	2	1	3
26.	Trucks (Limestone and Waste Cake)	2	1	3	8	2	10
27.	Bulldozer (Waste Cake)	1	1	2	2	1	3
28.	Limestone Storage Silo (30 Day)	1	1	2	2	1	3

		Plan No. 1			Plan No. 2		
		Operating	Spare	Total	Operating	Spare	Total
29.	Reclaim Hopper	1	0	1	1	0	1
30.	ID Booster Fan	2	0	2	2	0	2
31.	System Inlet Damper	1	0	1	1	0	1
32.	System Outlet Damper	1	0	1	1	0	1
33.	Absorber Inlet Dampers	2	1	3	3	1	4
34.	Absorber Outlet Dampers	2	1	3	3	1	4
35.	System Bypass Damper	1	0	1	1	0	1
36.	Booster Fan Inlet Dampers	2	0	2	2	0	2
37.	Booster Fan Outlet Dampers	2	0	2	2	0	2
38.	Reheat Fan Inlet Dampers	0	0	0	2	0	2
39.	Reheat Fan Outlet Dampers	0	0	0	2	0	2
40.	Absorber Flow Control Dampers	2	1	3	3	1	4

BC Hydro
Hat Creek Project
500 MW

EXHIBIT NO. 3

ELECTRICAL LOAD ASSOCIATED WITH FGD SYSTEM (ORDER OF MAGNITUDE)

	Plan 1					Plan 2				
	Operating		Spare			Operating		Spare		
List of Major Drives	Unit x HP/Unit	Total HP	Unit x HP/Unit	Total HP	Total Installed HP	Unit x HP/Unit	Total HP	Unit x HP/Unit	Total HP	Total Installed HP
1) Reheater Fan	0	0	0	0	0	2 x 1400	2 800	0	0	2 800
2) Booster Fan	2 x 1500	3 000	0	0	3 000	2 x 2450	4 900	0	0	4 900
3) Pumps - Recycle	8 x 395	3 160	4 x 395	1 580	4 740	12 x 516	6 192	4 x 516	2 064	8 256
4) - Mist Eliminator	1 x 152	152	1 x 152	152	304	1 x 365	365	1 x 365	365	730
5) - Waste Slurry	1 x 5	5	1 x 5	5	10	1 x 5	5	1 x 5	5	10
6) - Makeup Slurry	1 x 5	5	1 x 5	5	10	1 x 5	5	1 x 5	5	10
7) - Reclaim Water	1 x 30	30	1 x 30	30	60	1 x 30	30	1 x 30	30	60
8) - Thickener	1 x 5	5	1 x 5	5	10	1 x 5	5	1 x 5	5	10
9) Agitator - Recycle	2 x 100	200	1 x 100	100	300	3 x 100	300	1 x 100	100	400
10) - Waste Slurry	1 x 50	50	0	0	50	1 x 50	50	0	0	50
11) - Alkali Storage	1 x 50	50	0	0	50	1 x 50	50	0	0	50
12) Feeder	1 x 10	10	1 x 10	10	20	1 x 20	20	1 x 20	20	40
13) Ball Mill	1 x 100	100	1 x 100	100	200	1 x 200	200	1 x 200	200	400
14) Vacuum Filter	1 x 100	100	1 x 100	100	200	3 x 150	450	1 x 150	150	600
15) Mixer	1 x 120	120	1 x 120	120	240	2 x 175	350	1 x 175	175	525
16) Dampers	13 x 5	65	3 x 5	15	80	20 x 5	100	3 x 5	15	115
17) Thickener Rake	1 x 50	50	0	0	50	1 x 50	50	0	0	50
18) Filter Pump	1 x 10	10	1 x 10	10	20	3 x 15	45	1 x 15	15	60
19) Vacuum Pump	2 x 50	100	1 x 50	50	150	6 x 50	300	2 x 50	50	350
20) Conveyors		75	0	0	75		125	0	0	125
TOTAL HP		7 287			9 569		16 342			19 541

British Columbia Hydro
Hat Creek Project
500 MW

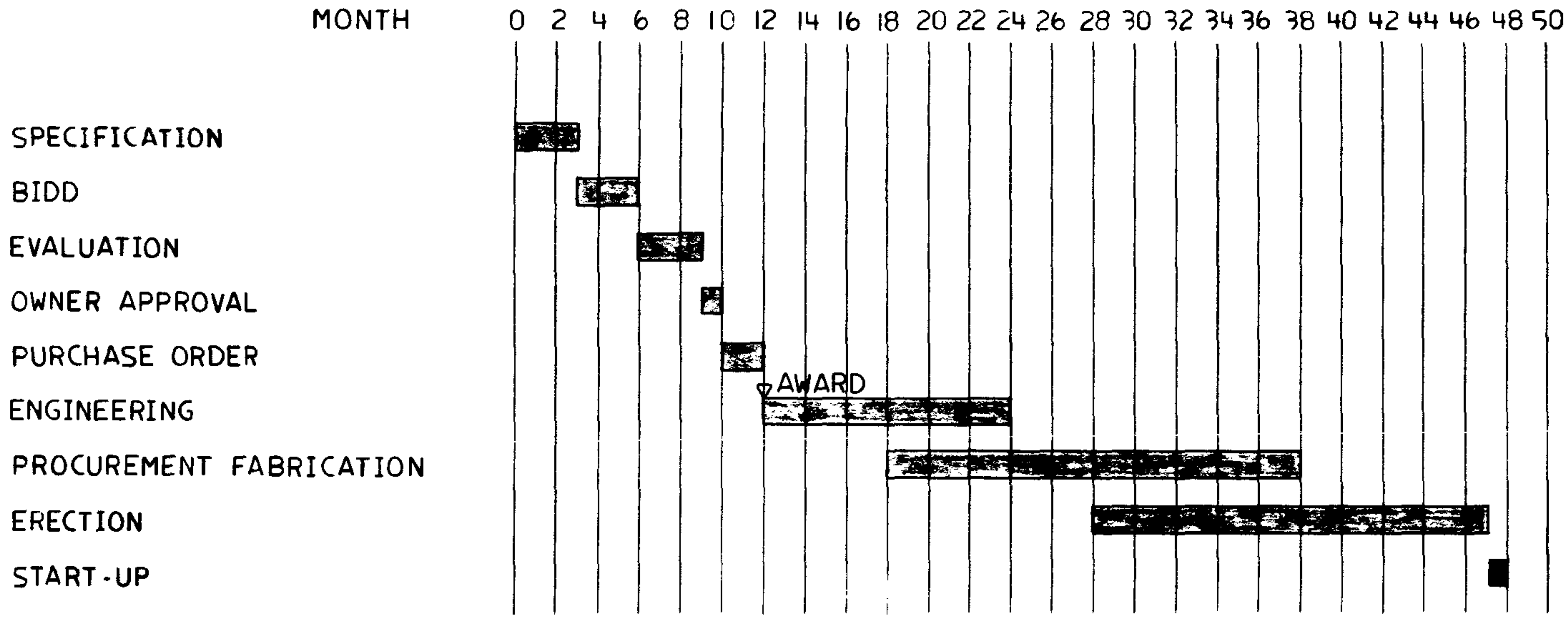
EXHIBIT NO. 4

MATERIAL BALANCE

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Description	ID Fan Discharge	Bypass	Scrubber Inlet Gas	Scrubber Outlet Gas	Ambient Air Reheat	Stack Gas	Steam	Condensate	Makeup Water	Service Water	Alkali Feed	Makeup Slurry	Recycle Slurry	Thickener Underflow	Filter Cake	Mist Eliminator Wash	Blending With Fly Ash	Fixation With CaO	Disposal Cake
Plan No. 1																			
Flow gpm (ACFM)	(1 200 000)	(1 111 200)	(644 400)	(524 102)	-	(2 324 638)			235	100	3.8 TPH	17	41 930	44	9.8 TPH	762			12.92 TPH
Temperature, °F	310	310	310	114		203			60	60		100	114	100		114			
Pressure, psig ("wg)	(+6)	(6)	(6)	(2)		(0)			100	100		50	50	30		80			
SO_2 ppm Dry	580	580	580	58		300													
Density SP G2 (PCF)	(.04372)	(.04372)	(.04372)	(.057)		(.047)			1.0	1.0		1.26	1.05	1.33		1.0			
Components, lb/hr																			
SO_2	3 919	3 628	2 105	210		4 048													
N_2, CO_2, O_2	3 096 081	2 866 972	1 662 595	1 663 424		6 193 820													
H_2O	100 000	92 600	53 700	132 505		357 610			117 617	50 000		7 018		17 723	7 877	381 000			7 877
$CaCO_3$ (CaO)											6 802	3 401		887	887			(236)	1 123
$CaSO_4$ $2H_2O$														10 172	10 172				10 172
Other Solids											756	378		756	756		5 903		6 659
TOTAL	3 200 000	2 963 200	1 718 400	1 796 139		6 555 478			117 617	50 000	7 558	10 797		29 538	19 692	381 000	5 903	(236)	25 831
Plan No. 2																			
Flow gpm (ACFM)	(1 225 813	0	(817 208)	(671 702)	(638 283)	(2 950 657)			535	123	15.33 TPH	46	53 736	180	39.93 TPH	977			50.85 TPH
Temperature, °F	310		310	122	60	170			60	60		60	122	100		100			
Pressure, psig ("wg)	(6)		6	(2)	(0)	(0)			100	100		50	50	40		80			
SO_2 ppm Dry	1 349		1 349	194	0	145													
Density SP G2 (PCF)	(.04372)		(.04372)	(.05635)	(.061)	(.05168)			1.0	1.0		1.26	1.05	1.33		1.0			
Components, lb/hr																			
SO_2	8 977		5 985	868		2 604													
N_2, CO_2, O_2	3 091 023		2 060 682	2 060 920	2 336 114	8 524 874													
H_2O	167 000		111 333	207 438		622 314	146 007	146 007	267 367	61 500		18 972		71 832	31 925	488 500			31 944
$CaCO_3$ (CaO)											27 560	9 194		3 598	3 598			(956)	4 554
$CaSO_4$ $2H_2O$														41 228	41 228				41 253
Other Solids											3 062	1 022		3 062	3 062		23 958		27 023
TOTAL	3 267 000	0	2 178 000	2 271 226	2 336 114	9 149 792	146 007	146 007	267 394	61 500	30 622	29 188		119 720	79 813	488 500	23 958	(956)	101 709

EXHIBIT 5

PROJECT SCHEDULE



EBASCO SERVICES INCORPORATED		BRITISH COLUMBIA-HYDRO HAT CREEK PROJECT FOR EACH 500MW FGD	EXHIBIT 5
DIV. MECH DR. W.A	APPROVED		
CH.			
DATE			

BC Hydro
Hat Creek Project
Flue Gas Desulfurization System (SO_2 Scrubbing)

EXHIBIT NO. 6

ORDER OF MAGNITUDE INVESTMENT (US BASIS $1000)

	Plan No. 1							Plan No. 2						
			Including Escalation							Including Escalation				
	Unit 1 Cost 4/77	Each Unit 2, 3 & 4 Cost 4/77	Unit 1	Unit 2	Unit 3	Unit 4	Total	Unit 1 Cost 4/77	Each Unit 2, 3 & 4 Cost 4/77	Unit 1	Unit 2	Unit 3	Unit 4	Total
A. Total Direct Construction Cost*	43 480	31 600	60 872	47 400	50 560	54 352	213 184	61 440	45 600	86 016	68 400	72 960	78 432	305 808
B. Indirect Construction Cost (1.7%) of A	739	537	1 035	805	860	924	3 624	1 044	775	1 462	1 163	1 240	1 333	5 199
C. Subtotal	44 219	32 134	61 907	48 205	51 420	55 276	216 808	62 484	46 375	87 478	69 563	74 200	79 765	311 007
D. Contingencies 12% of C	5 306	3 856	7 429	5 785	6 170	6 633	26 017	7 498	5 565	10 497	8 348	8 904	9 572	37 321
E. Total Construction Cost	49 525	35 990	69 336	53 990	57 590	61 909	242 825	69 982	51 940	97 975	77 911	83 104	89 337	348 327
F. Allowance For Engineering 4% of E	1 975	1 440	2 774	2 160	2 310	2 471	9 715	2 798	2 080	3 925	3 119	3 326	3 573	13 943
Total FGD Cost	51 500	37 430	72 110	56 150	59 900	64 380	252 540	72 780	54 020	101 900	81 030	86 430	92 910	362 270
Differential Investment							Base							+109 723
$/kW (Average 1977)	82.64							117.41						

*Include Pond, Land, Trucks, Bulldozer

British Columbia Hydro
Hat Creek Project

EXHIBIT NO. 7
Sheet 1 of 2

ANNUAL OWNING & OPERATING COST FACTORS & QUANTITIES

Item	Cost Factor	Units	Plan No. 1 Unit No. 1	Plan No. 1 Unit No. 2	Plan No. 1 Unit No. 3	Plan No. 1 Unit No. 4	Plan No. 1 Total	Plan No. 2 Unit No. 1	Plan No. 2 Unit No. 2	Plan No. 2 Unit No. 3	Plan No. 2 Unit No. 4	Plan No. 2 Total
1) Fixed Charge on Investment	13.78% of Investment	$1000 Invest.	72 109	56 150	59 894	64 385	252 538	101 895	81 028	86 428	92 910	362 261
2) Capacity & Replacement Energy Charge	$428/kW x .65 CF**	kW	5 430	5 430	5 430	5 430	21 720	12 176	12 176	12 176	12 176	48 704
3) Steam Consumption	$0.0016/lb x .65 CF*	lb/yr	0	0	0	0	0	1279×10^6	1279×10^6	1279×10^6	1279×10^6	5116×10^6
4) Reagent Consumption												
a) Limestone (Truck)	$16/ton x .65 CF*	T/yr	33 288	33 288	33 288	33 288	133 152	134 291	134 291	134 291	134 291	537 164
b) Lime Additive	$56/ton x .65 CF*	T/yr	1 034	1 034	1 034	1 034	4 136	4 187	4 187	4 187	4 187	16 748
5) Operating Labor Cost	$32/Man Hr*	Man Hour Year (3 Shift)	24 000	24 000	24 000	24 000	96 000	30 000	30 000	30 000	30 000	120 000
6) Maintenance Material & Labor	3% of Investment*	$1000 Invest.	72 109	56 150	59 894	64 385	252 538	101 895	81 028	86 428	92 910	362 261

*Levelized Factor = 2.443

**20 Mills/kWh Power Cost including Capital Component

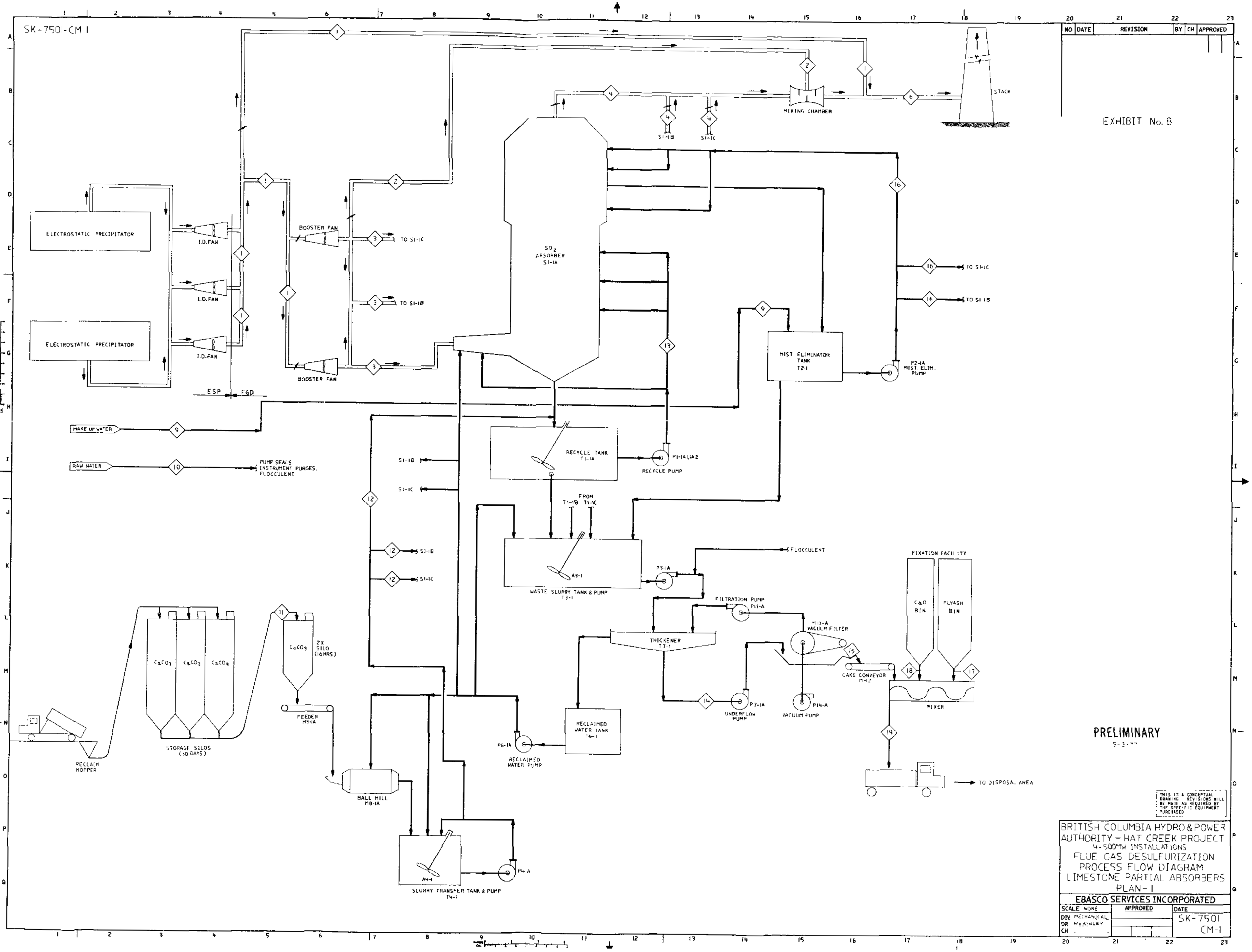
$\frac{20 \text{ Mills}}{\text{kWh}} \times 8760 = \$175.2/\text{kW} \times 2.443 = \$428/\text{kW}$

British Columbia Hydro
Hat Creek Project

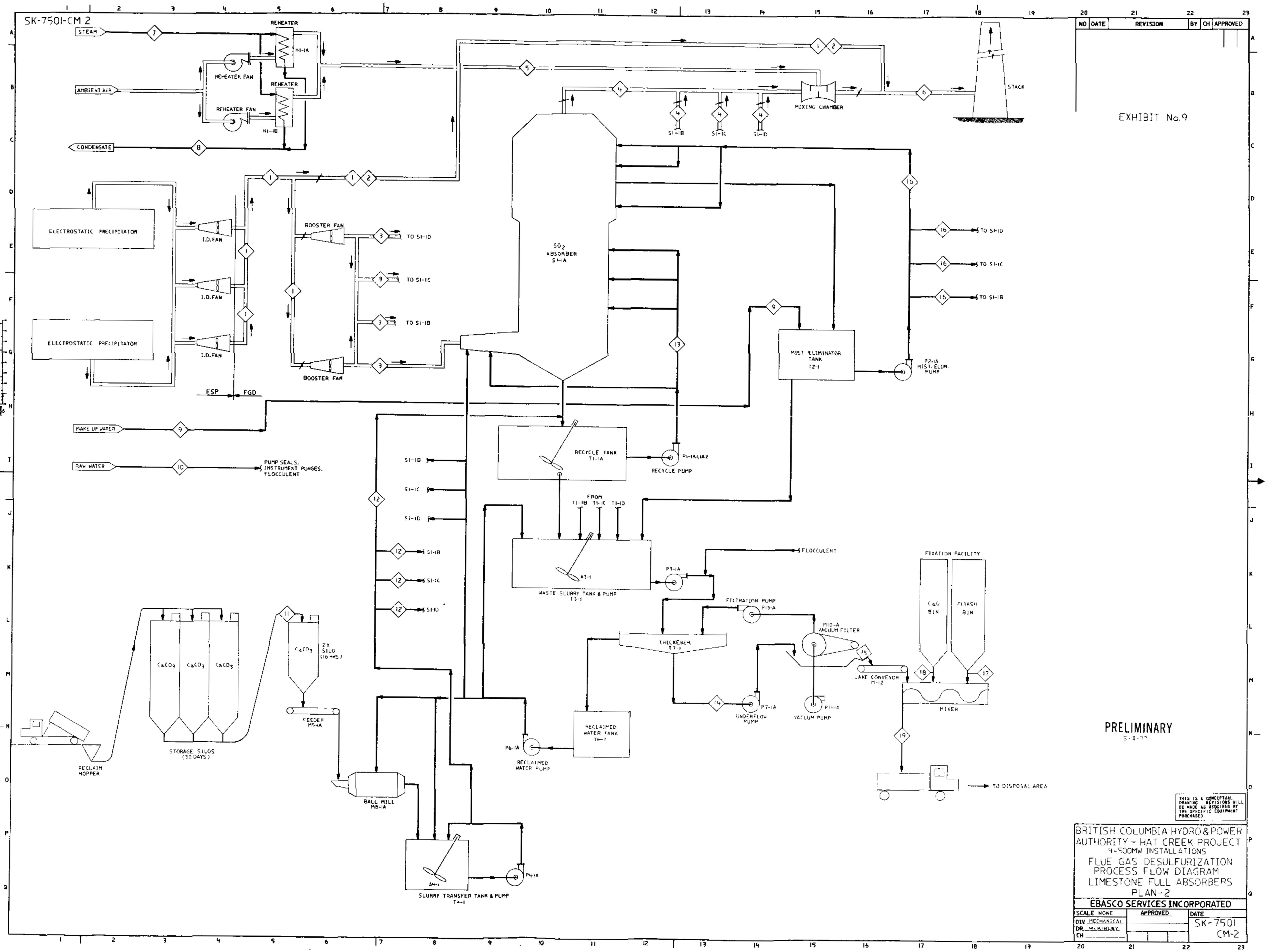
EXHIBIT NO. 7
Sheet 2 of 2

CAPITALIZED ANNUAL OWNING & OPERATING COST (US $1000)

Item	Plan No. 1 Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total	Plan No. 2 Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total
1) Fixed Charge on Investment	9 937	7 737	8 253	8 872	34 799	14 041	11 166	11 910	12 803	49 920
2) Capacity & Replacement Energy Charge	1 511	1 511	1 511	1 511	6 044	3 387	3 387	3 387	3 387	13 548
3) Steam Consumption	0	0	0	0	0	1 330	1 330	1 330	1 330	5 320
4) Reagent Consumption										
a) Limestone	346	346	346	346	1 384	1 396	1 396	1 396	1 396	5 584
b) Lime Additive	38	38	38	38	152	153	153	153	153	612
5) Operating Labor Cost	768	768	768	768	3 072	960	960	960	960	3 840
6) Maintenance Material & Labor	2 163	1 684	1 797	1 931	7 575	3 057	2 431	2 592	2 787	10 867
7) Total Annual Owning & Operating Cost	14 763	12 084	12 713	13 466	53 026	24 327	20 823	21 728	22 816	89 691
Differential					Base					36 665
8) Capitalized Owning & Operating Cost	107 713	87 692	92 257	97 721	384 803	176 538	151 110	157 678	165 573	650 879
Differential					Base					277 624



SK-7501-CM I
EXHIBIT No. 8
NO DATE REVISION BY CH APPROVED
ELECTROSTATIC PRECIPITATOR
ELECTROSTATIC PRECIPITATOR
I.D. FAN
I.D. FAN
I.D. FAN
BOOSTER FAN
BOOSTER FAN
TO S1-1C
TO S1-1B
ESP
FGD
SO_2 ABSORBER S1-1A
MIXING CHAMBER
STACK
S1-1B
S1-1C
MIST ELIMINATOR TANK T2-1
P2-1A MIST. ELIM. PUMP
TO S1-1C
TO S1-1B
MAKE UP WATER
RAW WATER
PUMP SEALS, INSTRUMENT PURGES, FLOCCULENT
RECYCLE TANK T1-1A
P1-1A,1A2
RECYCLE PUMP
S1-1B
S1-1C
FROM T1-1B T1-1C
WASTE SLURRY TANK & PUMP T3-1
A3-1
P3-1A
FLOCCULENT
S1-1B
S1-1C
FILTRATION PUMP
P13-A
THICKENER T7-1
F10-A VACUUM FILTER
P7-1A UNDERFLOW PUMP
P14-A VACUUM PUMP
CAKE CONVEYOR M-12
FIXATION FACILITY
CaO BIN
FLYASH BIN
MIXER
TO DISPOSAL AREA
RECLAIMED WATER TANK T6-1
P6-1A
RECLAIMED WATER PUMP
$CaCO_3$
$CaCO_3$
$CaCO_3$
STORAGE SILOS (30 DAYS)
RECLAIM HOPPER
$CaCO_3$
2X SILO (16HRS)
FEEDER M5-1A
BALL MILL M8-1A
A4-1
P4-1A
SLURRY TRANSFER TANK & PUMP T4-1
PRELIMINARY
THIS IS A CONCEPTUAL DRAWING. REVISIONS WILL BE MADE AS REQUIRED BY THE SPECIFIC EQUIPMENT PURCHASED
BRITISH COLUMBIA HYDRO & POWER AUTHORITY – HAT CREEK PROJECT
4-500MW INSTALLATIONS
FLUE GAS DESULFURIZATION PROCESS FLOW DIAGRAM
LIMESTONE PARTIAL ABSORBERS
PLAN-1
EBASCO SERVICES INCORPORATED
SCALE NONE
APPROVED
DATE
DIV MECHANICAL
DR McKINLEY
CH
SK-7501
CM-1


SK-7501-CM 2
NO | DATE | REVISION | BY | CH | APPROVED
EXHIBIT No.9
STEAM
AMBIENT AIR
CONDENSATE
REHEATER
REHEATER FAN
H1-1A
H1-1B
STACK
MIXING CHAMBER
S1-1B
S1-1C
S1-1D
ELECTROSTATIC PRECIPITATOR
ELECTROSTATIC PRECIPITATOR
I.D. FAN
BOOSTER FAN
TO S1-1D
TO S1-1C
TO S1-1B
ESP
FGD
SO_2 ABSORBER S1-1A
MIST ELIMINATOR TANK T2-1
P2-1A MIST ELIM. PUMP
TO S1-1D
TO S1-1C
TO S1-1B
MAKE UP WATER
RAW WATER
PUMP SEALS, INSTRUMENT PURGES, FLOCCULENT
RECYCLE TANK T1-1A
RECYCLE PUMP
P1-1A,1A2
FROM T1-1B T1-1C T1-1D
WASTE SLURRY TANK & PUMP T3-1
A3-1
P3-1A
FLOCCULENT
FILTRATION PUMP P13-A
THICKENER T7-1
M10-A VACUUM FILTER
CAKE CONVEYOR M-12
FIXATION FACILITY
CaO BIN
FLYASH BIN
MIXER
UNDERFLOW PUMP
P7-1A
VACUUM PUMP
P14-A
RECLAIMED WATER TANK T6-1
P6-1A
RECLAIMED WATER PUMP
$CaCO_3$
STORAGE SILOS (30 DAYS)
2X SILO (16 HRS)
FEEDER M54A
RECLAIM HOPPER
BALL MILL M8-1A
SLURRY TRANSFER TANK & PUMP T4-1
A4-1
P4-1A
TO DISPOSAL AREA
PRELIMINARY
THIS IS A CONCEPTUAL DRAWING. REVISIONS WILL BE MADE AS REQUIRED BY THE SPECIFIC EQUIPMENT PURCHASED.
BRITISH COLUMBIA HYDRO & POWER AUTHORITY - HAT CREEK PROJECT
4-500MW INSTALLATIONS
FLUE GAS DESULFURIZATION PROCESS FLOW DIAGRAM LIMESTONE FULL ABSORBERS PLAN-2
EBASCO SERVICES INCORPORATED
SCALE NONE
APPROVED
DATE
DIV MECHANICAL
SK-7501 CM-2

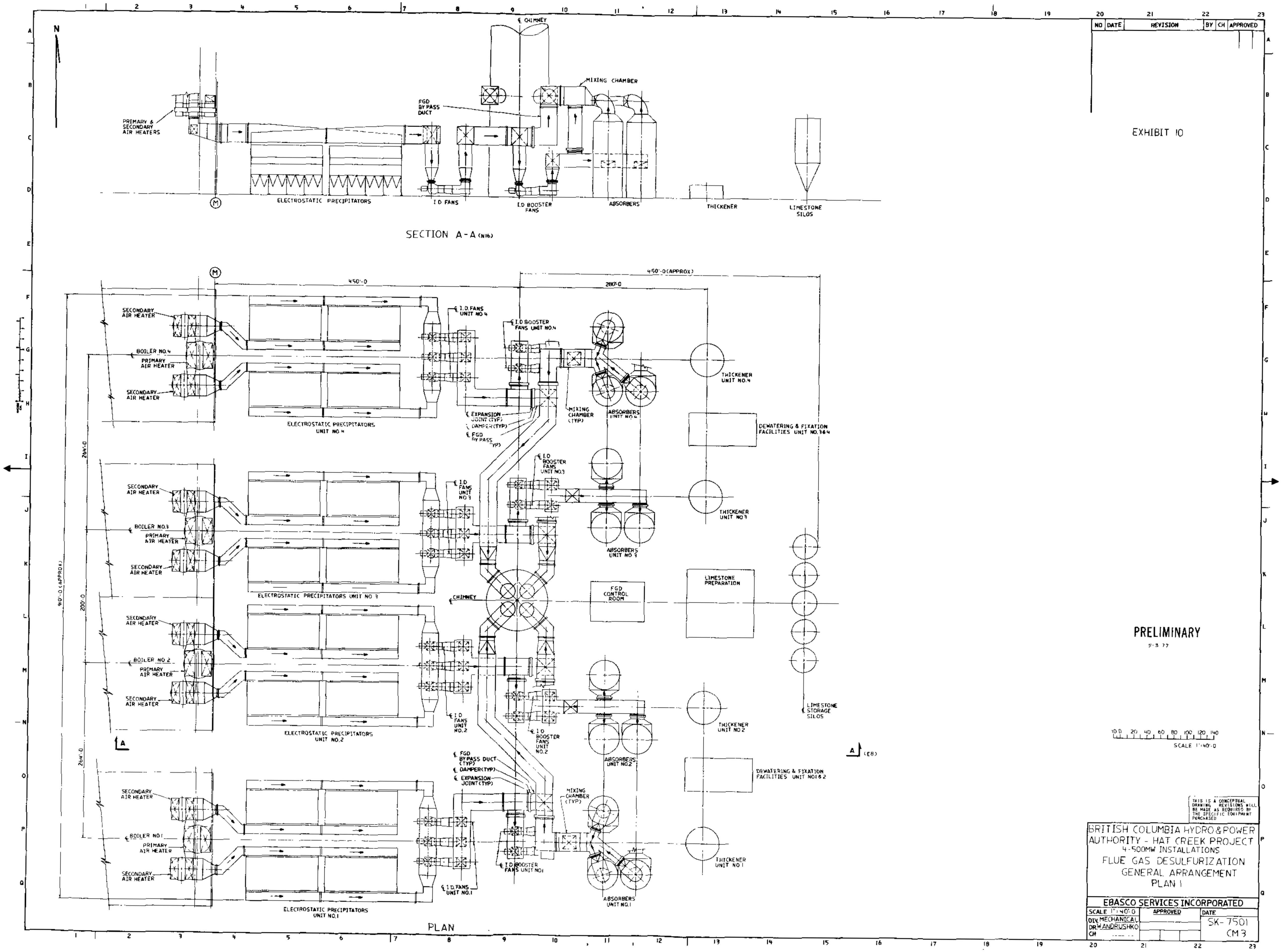


EXHIBIT 10
NO | DATE | REVISION | BY | CH | APPROVED
MIXING CHAMBER
FGD BY PASS DUCT
PRIMARY & SECONDARY AIR HEATERS
ELECTROSTATIC PRECIPITATORS
I.D FANS
I.D BOOSTER FANS
ABSORBERS
THICKENER
LIMESTONE SILOS
SECTION A-A
450'-0
450'-0 (APPROX)
200'-0
SECONDARY AIR HEATER
BOILER NO.4
PRIMARY AIR HEATER
I.D. FANS UNIT NO.4
I.D BOOSTER FANS UNIT NO.4
THICKENER UNIT NO.4
ELECTROSTATIC PRECIPITATORS UNIT NO.4
EXPANSION JOINT (TYP)
DAMPER (TYP)
FGD BY PASS (TYP)
MIXING CHAMBER (TYP)
ABSORBERS UNIT NO.4
DEWATERING & FIXATION FACILITIES UNIT NO.3 & 4
BOILER NO.3
I.D FANS UNIT NO.3
I.D BOOSTER FANS UNIT NO.3
THICKENER UNIT NO.3
ABSORBERS UNIT NO.3
ELECTROSTATIC PRECIPITATORS UNIT NO.3
CHIMNEY
FGD CONTROL ROOM
LIMESTONE PREPARATION
PRELIMINARY
BOILER NO.2
LIMESTONE STORAGE SILOS
I.D FANS UNIT NO.2
I.D BOOSTER FANS UNIT NO.2
THICKENER UNIT NO.2
ELECTROSTATIC PRECIPITATORS UNIT NO.2
ABSORBERS UNIT NO.2
DEWATERING & FIXATION FACILITIES UNIT NO.1 & 2
FGD BY PASS DUCT (TYP)
DAMPER (TYP)
EXPANSION JOINT (TYP)
MIXING CHAMBER (TYP)
BOILER NO.1
I.D BOOSTER FANS UNIT NO.1
I.D FANS UNIT NO.1
THICKENER UNIT NO.1
ABSORBERS UNIT NO.1
ELECTROSTATIC PRECIPITATORS UNIT NO.1
PLAN
SCALE 1"=40'-0
THIS IS A CONCEPTUAL DRAWING. REVISIONS WILL BE MADE AS REQUIRED BY THE SPECIFIC EQUIPMENT PURCHASED
BRITISH COLUMBIA HYDRO & POWER AUTHORITY - HAT CREEK PROJECT
4-500MW INSTALLATIONS
FLUE GAS DESULFURIZATION
GENERAL ARRANGEMENT
PLAN I
EBASCO SERVICES INCORPORATED
SCALE 1"=40'-0
APPROVED
DATE
DIV. MECHANICAL
DR. WANDRUSHKO
CH
SK-7501
CM 3

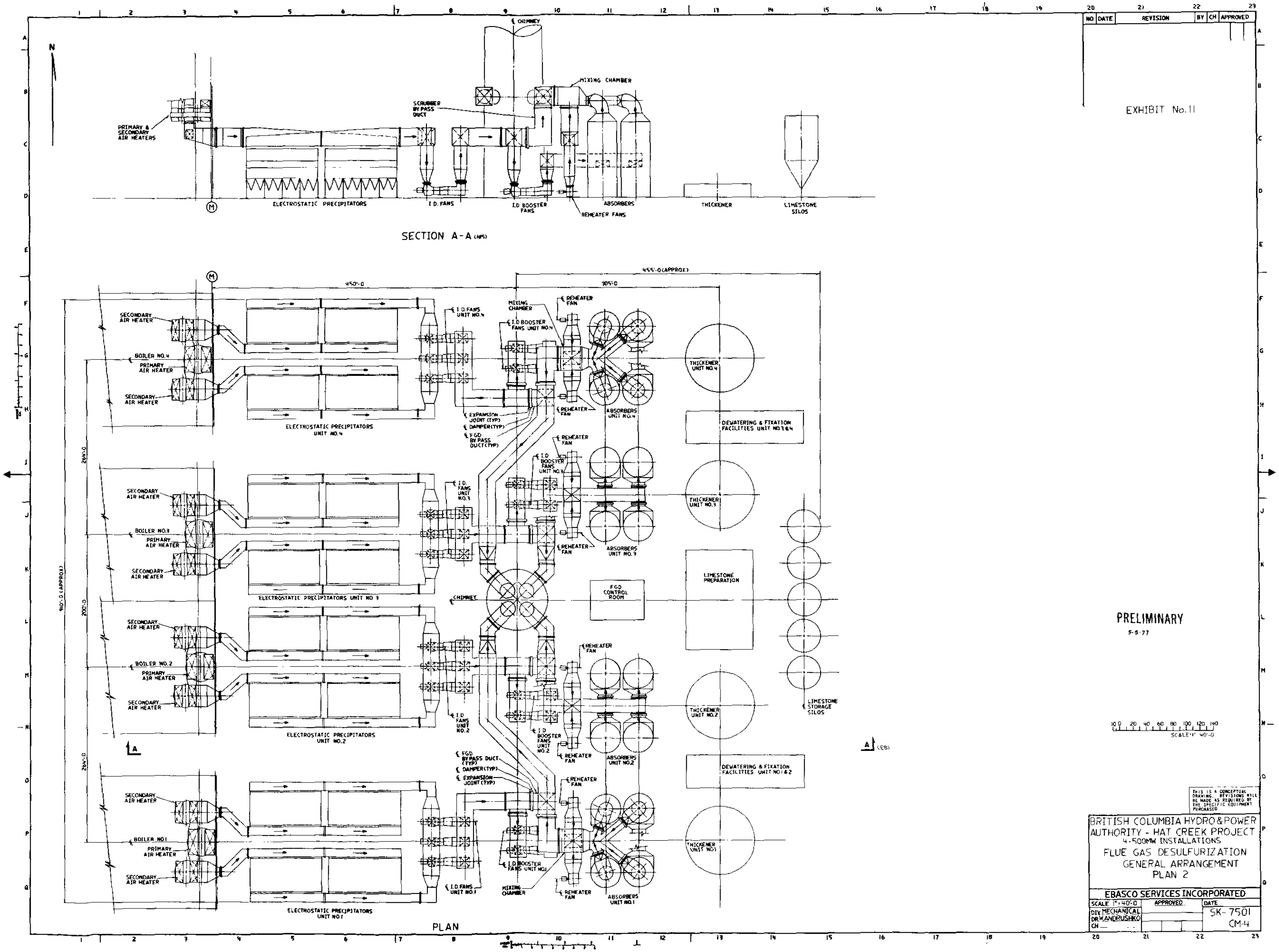
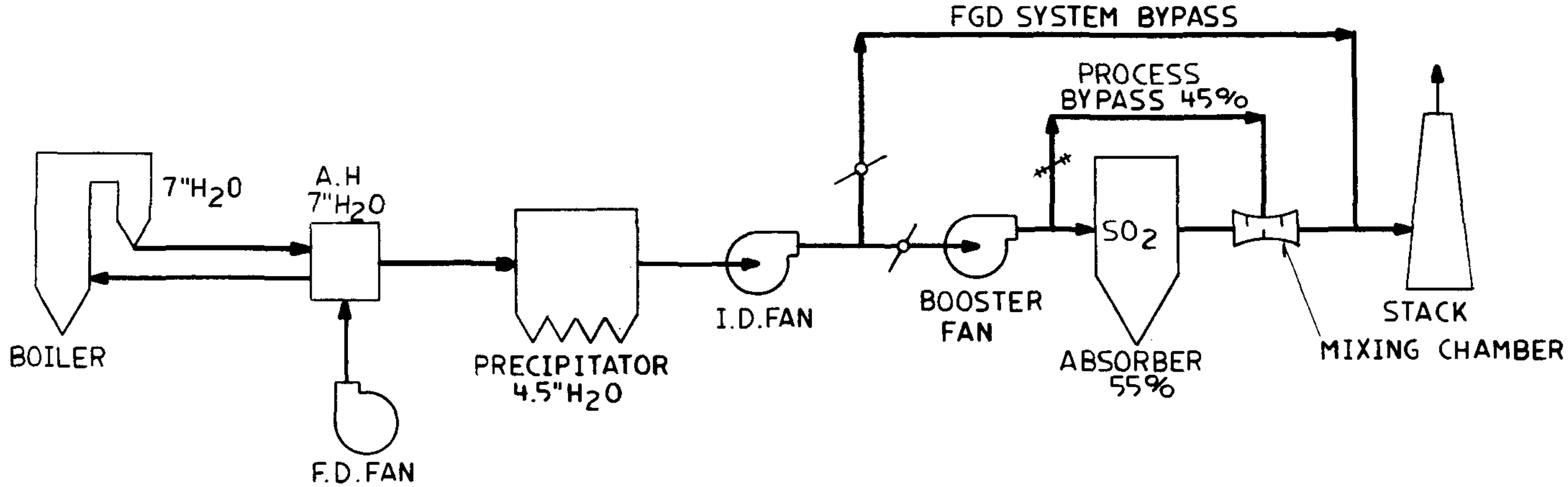
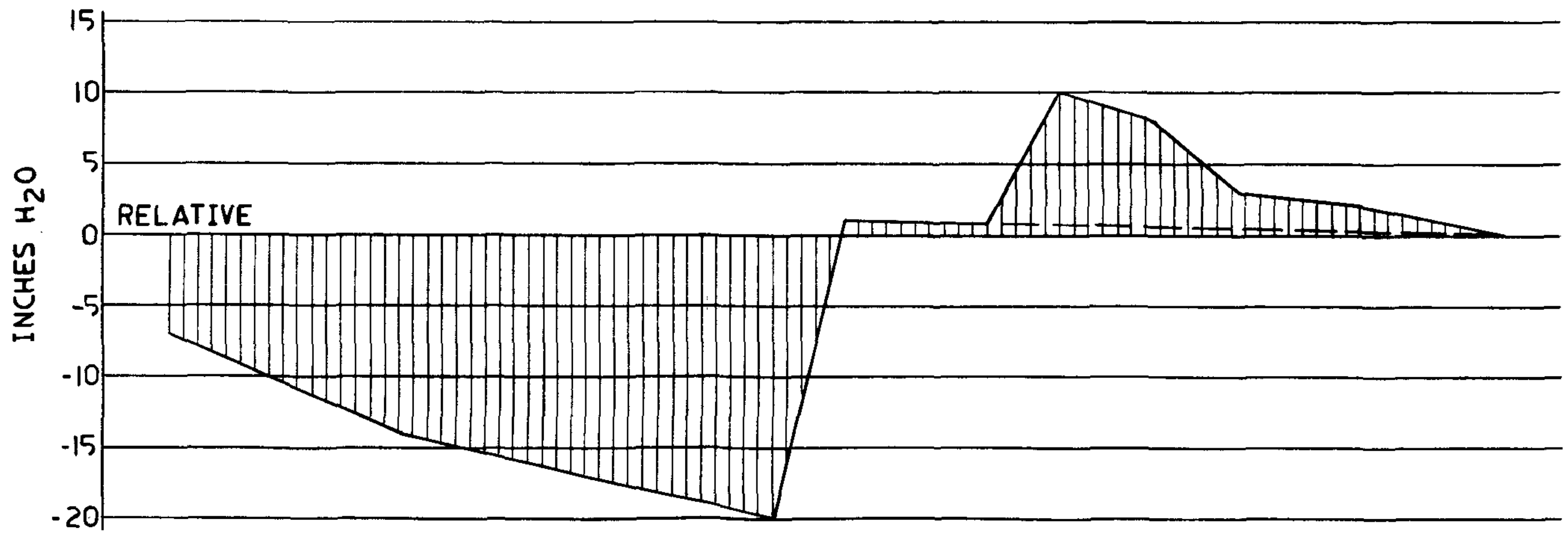


EXHIBIT No. 11
CHIMNEY
MIXING CHAMBER
SCRUBBER BY PASS DUCT
PRIMARY & SECONDARY AIR HEATERS
ELECTROSTATIC PRECIPITATORS
I.D. FANS
I.D BOOSTER FANS
ABSORBERS
REHEATER FANS
THICKENER
LIMESTONE SILOS
SECTION A-A (NTS)
450'-0
455'-0 (APPROX)
105'-0
SECONDARY AIR HEATER
BOILER NO.4
PRIMARY AIR HEATER
ELECTROSTATIC PRECIPITATORS UNIT NO.4
I.D. FANS UNIT NO.4
I.D BOOSTER FANS UNIT NO.4
REHEATER FAN
ABSORBERS UNIT NO.4
THICKENER UNIT NO.4
DEWATERING & FIXATION FACILITIES UNIT NO.3 & 4
EXPANSION JOINT (TYP)
DAMPER (TYP)
FGD BY PASS DUCT (TYP)
BOILER NO.3
ELECTROSTATIC PRECIPITATORS UNIT NO.3
I.D. FANS UNIT NO.3
I.D BOOSTER FANS UNIT NO.3
ABSORBERS UNIT NO.3
THICKENER UNIT NO.3
LIMESTONE PREPARATION
FGD CONTROL ROOM
CHIMNEY
BOILER NO.2
ELECTROSTATIC PRECIPITATORS UNIT NO.2
I.D. FANS UNIT NO.2
I.D BOOSTER FANS UNIT NO.2
ABSORBERS UNIT NO.2
THICKENER UNIT NO.2
LIMESTONE STORAGE SILOS
DEWATERING & FIXATION FACILITIES UNIT NO.1 & 2
BOILER NO.1
ELECTROSTATIC PRECIPITATORS UNIT NO.1
I.D. FANS UNIT NO.1
I.D BOOSTER FANS UNIT NO.1
MIXING CHAMBER
ABSORBERS UNIT NO.1
THICKENER UNIT NO.1
264'-0
200'-0
910'-0 (APPROX)
PLAN
PRELIMINARY
5-5-77
SCALE: 1" = 40'-0
THIS IS A CONCEPTUAL DRAWING. REVISIONS WILL BE MADE AS REQUIRED BY THE SPECIFIC EQUIPMENT PURCHASED
BRITISH COLUMBIA HYDRO & POWER AUTHORITY - HAT CREEK PROJECT
4-500MW INSTALLATIONS
FLUE GAS DESULFURIZATION GENERAL ARRANGEMENT PLAN 2
EBASCO SERVICES INCORPORATED
SCALE 1" = 40'-0
APPROVED
DATE
DIV. MECHANICAL
DR. W. ANDRUSHKO
CH
SK-7501
CM-4

EXHIBIT 12



BASIC SYSTEM FLOW ARRANGEMENT
PLAN NO.1



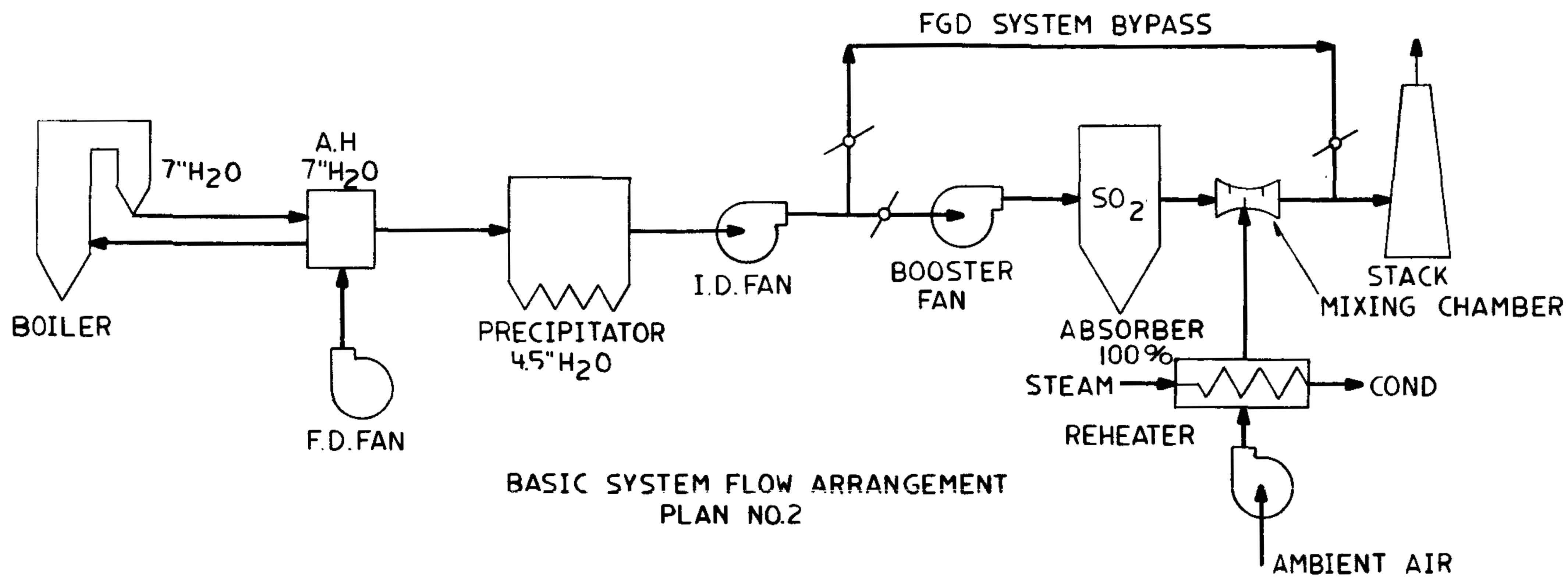
EBASCO SERVICES INCORPORATED

DIV. MECH DR. W.A.
CH.
DATE MAY 4, 1977
APPROVED

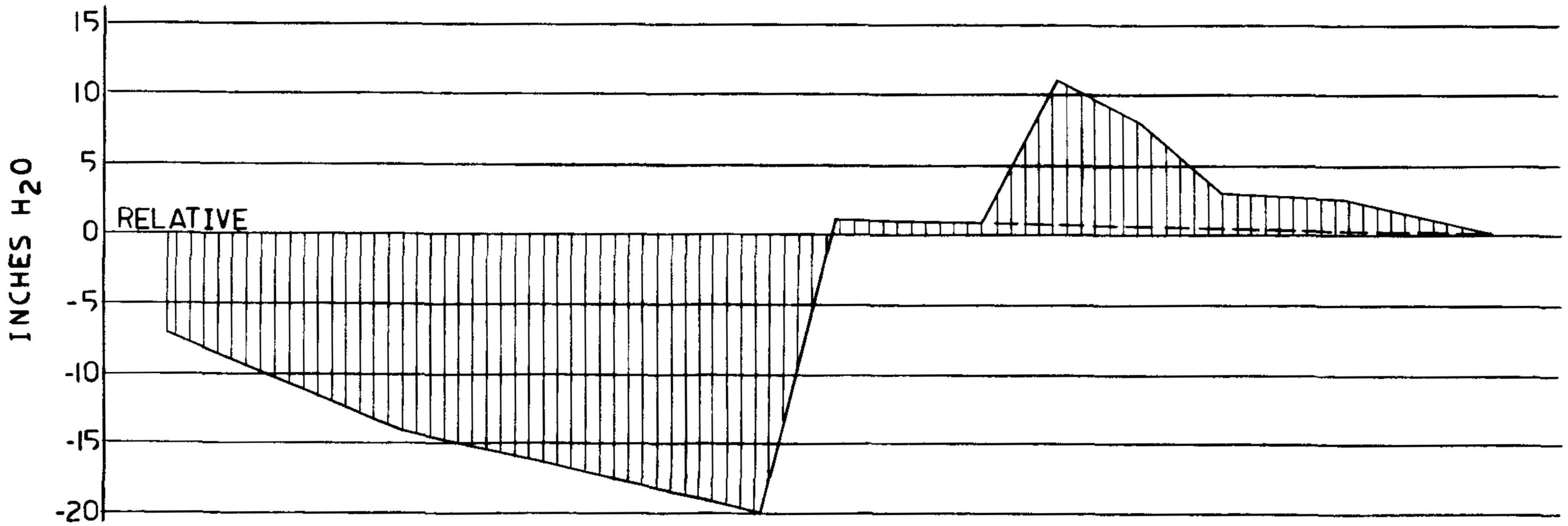
BRITISH COLUMBIA-HYDRO
HAT CREEK PROJECT
FGD STUDY 500MW

EXHIBIT 12

EXHIBIT 13



BASIC SYSTEM FLOW ARRANGEMENT
PLAN NO.2



EBASCO SERVICES INCORPORATED	APPROVED	BRITISH COLUMBIA-HYDRO HAT CREEK PROJECT FGD STUDY 500 MW	EXHIBIT 13
DIV. MECH DR. W.A. CH. DATE MAY. 4, 1977			

FULL-SCALE FGD PROGRAMS ON BOILERS IN THE UNITED STATES
(STARTUP BY 1976)
(All Coal Fired Except Two Marked)

Year of Startup	Facility	Size of Facility
Limestone Injection Wet Scrubbing		
1968	Union Electric - Meramec	140 MW
1968	Kansas P&L - Lawrence	125 MW
1971	Kansas P&L - Lawrence	400 MW
1972	Kansas City P&L - Hawthorn	125 MW
1972	Kansas City P&L - Hawthorn	140 MW
Limestone Scrubbing		
1972	Commonwealth Edison - Will County	165 MW
1973	City of Key West - Stock Island	42 MW
1973	Kansas City P&L - La Cygne	820 MW
1973	Arizona Public Service - Cholla	125 MW
1974	Southern California Edison - Mohave	160 MW (a)
1975	Detroit Edison - St Clair	180 MW
1976	Northern States Power - Sherburn County	680 MW
1976	Central Illinois Light - Duck Creek	100 MW
1976	Springfield City Utilities - Southwest	200 MW
1977	Texas Utilities - Martin Lake	793 MW
Lime Scrubbing		
1973	Louisville G&E - Paddy's Run	70 MW
1973	Duquesne Light - Phillips	387 MW
1974	Southern California Edison - Mohave	170 MW (a)
1975	Ohio Edison - Bruce Mansfield	825 MW
1975	Duquesne Light - Elrama	510 MW
1975	Kentucky Utilities - Green River	64 MW
1976	Columbus & Southern Ohio - Conesville	400 MW
1976	Louisville G&E - Cane Run	178 MW
1976	Montana Power Co - Colstrip 1 & 2	720 MW

Year of Startup	Facility	Size of Facility
1976	Louisville G&E - Cane Run	183 MW
1976	Rickenbacker AFB	20 MW (b)
Alkali Scrubbing Without Regeneration		
1972	General Motors - St Louis Mo	15 & 8 MW (b)
1974	Nevada Power - Reid Gardner	125 MW
1974	Nevada Power - Reid Gardner	125 MW
1976	Nevada Power - Reid Gardner	125 MW
Alkali Scrubbing With Alkali Regeneration		
1974	General Motors - Parma, Ohio	32 MW (b,c)
1974	Caterpillar Tractor - Joliet, Ill	10 & 8 MW (b)
1975	Caterpillar Tractor - Mossville, Ill	15, 8, & 8 MW (b)
1975	Gulf Power - Scholz	20 MW
Alkali Scrubbing With Thermal Regeneration		
1976	Northern Indiana Public Service - D H Mitchell	115 MW
Magnesium Oxide Scrubbing		
1972	Boston Edison - Mystic	150 MW
1973	Potomac Electric - Dickerson	100 MW
1975	Philadelphia Electric - Eddystone	120 MW
Catalytic Oxidation		
1972	Illinois Power - Wood River	110 MW
Dilute Acid Scrubbing		
1975	Gulf Power - Scholz	23 MW
Activated Carbon		
1975	Gulf Power - Scholz	20 MW

(a) 20 percent of gas flow from 790 MW unit.
(b) Industrial boiler with equivalent MW rating.
(c) Four stoker-fired boilers.
Oil Fuel

EXHIBIT NO. 15

BRIEF STATUS SUMMARY ON REGENERABLE PROCESSES (a)

Process Name	Year, Installation Site, Vendor, Size & Type of Boiler	Status
Wellman-Lord	1976, D H Mitchell, NIPSCO, Davy Power-gas/Allied Chemical, 115 MW, coal	In operation
MgO Scrubbing	1972 Mystic, Boston Edison, Chemico, 150 MW, oil	Shutdown since June, 1974
	1974 Dickerson, Potomac Electric, Chemico, 100 MW, coal	Shutdown since July, 1975
	1975 Eddystone, Philadelphia Electric, UEC, 120 MW, coal	Shutdown for modification
Cat-Ox	1972 Wood River, Illinois Power Co, Monsanto, 110 MW, coal	Shutdown since 1974
Chiyoda	1975, Scholz power plant, Gulf Power Co Chiyoda, 23 MW, coal	Operating since June 1975
FW-BF	1975, Scholz power plant, Gulf Power Co Foster Wheeler, 20 MW coal	Started commissioning Jan 1975, many problems; shutdown
SFGD	1974, Big Bend Station, Tampa Electric UOP, 0.6 MW slipstream, coal	Tests are in progress
Citrate(b)	1973, Pfizer's Vigo Chemical complex, McKee/Peabody, 1 MW slipstream, coal	Shutdown September 1974 after data collection
Phosphate	1974, Norwalk Harbor Station, Connecticut Power & Light Co, Stauffer, 0.1 MW oil	Shutdown June 1974 after data collection
Catalytic IFP	No data in open literature	No data in open literature
Consol-Potassium	1972, Cromby, Philadelphia Electric Co Consol/Bechtel, 10 MW coal	Shutdown since 1972 after data collection (a smaller plant, 1000 ACFM was operated until 1975)
Al-Aqueous	1971 Mohave, So. Calif Edison, Al, 0.5 MW, oil	Shutdown 1972 after data collection on open loop system
Stone & Webster/ Ionics	1973 Valley Station, Wisconsin Electric Power, Stone & Webster/Ionics, 0.75 MW slipstream, coal	Shutdown 1974 after data collection
Westvaco	1970 Westvaco Research Center, Westvaco 0.2 MW, oil	Shutdown 1974 after data collection

(a) Installations in the United States only are discussed in this table.
(b) Extensive pilot plant studies on a lead smelter gas are being conducted by USBM Salt Lake City Metallurgy Research Center.