6.6.15 CAPACITY FACTORS

The utility requirements and unit costs for all the units in the Shell Coal Case are capacity factored from the Base Case. The capacity factors used and their basis for this case are tabulated in Table 6.6.15-1.

UNIT

UNIT

No.	Name		Basis
01	Coal Screening		Coal, TPD
02	Coal Distribution		Coal, TPD
03	Ash Handling		Gasifier Ash, TPD
10	Coal Gasification		Number of Gasifiers
11	CO Shift		Catalyst Volume, ft^3
12	Gas Cooling		Cooling Duty, MM Btu/hr
13	Rectisol		Acid Gas Removed, lb-mol/l
14	Gas Liquor Separation		Net Gas Liquor Feed, lb/hr
15	Tar Distillation		Tar/Oil Feed, lb/hr
16	Naphtha Hydrotreating		Naphtha Feed, lb/hr
17	Phenosolvan		Net Gas Liquor Feed, lb/hr
18	Ammonia Recovery		Ammonia Product Rate, lb/h
19	Sulfur Recovery - ADIP		Gas Feed, lb-mol/hr
			H_2S Absorbed, lb-mol/hr
		Claus	Sulfur Product Rate, TPD
		SCOT	Gas Feed, lb-mol/hr
		Stretford	Gas Feed, lb-mol/hr
			Sulfur Product Rate, TPD
20	Process Steam Superheating		Vent Gas Feed Rate, lb-mol,
			Fired Duty, MM Btu/hr
21	Methanol Synthesis		Methanol Production Rate, T
22	Methanation		Feed Rate, lb-mol/hr
23	SNG Purification & Compression		Feed Rate, lb-mol/hr
24	Partial Oxidation		Liquids Feed Rate, lb/hr
25	PSA H_2 Production		H_2 Production Rate, lb-mol/
40	Oxygen Production		O_2 Production Rate, TPD

TABLE 6.6.15-1

UNIT CAPACITY FACTORS

	Base Case	Shell Coal Coproduction Case	Factor
	18,000	17,600	0.978
	18,000	17,600	0.978
	827	448	0.541
	14	14	1.0
	4,055	4,746	1.170
tu/hr	673.9	643	0.984
lb-mol/hr	19,940	19,499	0.978
, lb/hr	1,000,636	1,001,404	1.001
	25,265	44,190	1.749
r	16,380	29,464	1.800
, lb/hr	969,596	951,570	0.981
te, lb/hr	6,398	7,526	1.176
r	690.9	625.6	0.905
ol/hr	114.4	53.4	0.467
, TPD	53.5	25.1	0.469
	898.3	759.0	0.845
	11,368.7	11,083.9	0.975
TPD	33.7	14.7	0.436
lb-mol/hr	21,870.2	20,484.8[1]	0.982[1]
/hr	320	283.9	0.887
Rate, TPD	30	30	1.0
	43,647.3	44,097.2	1.0
	18,207.5	18,204.6	1.0
b/hr	23,487	38,778	1.651
lb-mol/hr	118.6	192.1	1.620
TPD	2,925	3,007	1.028

TA

UNIT CA

UNIT No.	Name	Basis
41	Steam Generation	Steam Production Rate, M lb
		No. of Boilers
42	Power Generation	Generation Capacity, MW
		No. of Trains
43	Flue Gas Desulfurization	Flue Gas Feed Rate, MM SCF
		SO_2 Removed, lb-mol/hr
44	Raw Water Treating	Raw Water Flow Rate, gpm
45	BFW and Condensate Treating	Total BFW Flow Rate, gpm
46	Air and Nitrogen System	N_2 + Air Quantity, scfm
47	Process Cooling Water	Cooling Water Flow, gpm
48	Utility Cooling Water	Cooling Water Flow, gpm
49	Potable Water	Water flow, gpm
50	Utility Water	Design Capacity, gpm
51	Fire Water	Design Capacity, gpm
52	Fuel Gas	Fuel Gas Quantity, MM Btu/h
53	Flare	Design Capacity, MM lb/hr
54	Wastewater Treating	Wastewater Flowrate, gpm
55	Tank Farm & Dispatch	Working Capacity, BBL
	-Naphtha	
	-Ammonia	
	-Sulfur	
	-Intermediate: PONS	
	-MeOH	
	-Prop./IPE	
	-Inorg. Chemicals	

TABLE 6.6.15-1 (Continued)

UNIT CAPACITY FACTORS

	Base Case	Shell Coal Coproduction Case	Factor
ite, M lb/hr	4,120	4,250	1.034
	3	3	
, MW	405	422.8	1.05
	3	3	
, MM SCFM	1.2	1.24[1]	1.035[1]
l/hr	138	58.8[1]	0.458[1]
e, gpm	6813	7076	1.039
e, gpm	9977	10,000	1.002
scfm	23,100	23,100	1.0
gpm	152,000	159,600	1.050
gpm	64,900	68,700	1.059
	54	54	1.0
m	500	500	1.0
m	7500	7500	1.0
MM Btu/hr	369.2	314.1	0.851
M lb/hr	1.878	1.878	1.0
, gpm	2536	2566	1.012
BBL			
	41,200	74,100	1.799
	29,400	34,600	1.177
	7,800	3,600.462	
	68,100	110,300	1.620
	5,000	5,000	1.0
	5,550	5,550	1.0
	10,650	10,650	1.0

UNIT

No.	Name	Basis
56	Sanitary Sewer	-
57	Interconnecting Pipeway	-

NOTE (1): Minor discrepancy between the capacity factors indic
balance subsequent to cost estimating.

TABLE 6.6.15-1 (Continued)

UNIT CAPACITY FACTORS

	Base Case	Shell Coal Coproduction Case	Factor
	-	-	1.0
	-	-	1.0

's indicated and the ratio of flowrates is due to slight adjustments made in the material

6.7 PROCESS STUDIES

Three special process optimization studies were performed - a steam study, a comparison of flue gas desulfurization processes, and the expanded plant study.

6.7.1 STEAM STUDY

6.7.1.1 INTRODUCTION

The Crow synfuels plant uses coal fired boilers for the generation of steam. A 2400 psig boiler plant is proposed as an alternative to the 1500 psig boiler plant used in the Base Case process design.

The objectives of this steam study are to:

Increase steam pressure to 2400 psig to increase power generation

Determine resource requirements and net power generation

Develop capital and operating costs comparing the two steam systems

6.7.1.2 SUMMARY

The 2400 psig steam generation appears to have a slight advantage over the 1500 psig steam; however, the comparison should be made in greater detail during the next phase of this project.

The overall cost for the 1500 psig steam generation case plant has a $44 million capital cost advantage over the 2400 psig steam generation case. The 2400 psig case plant generates 31 MW more power than the 1500 psig case plant and has an operating cost advantage of $9.9 million per year. The 1500 psig case Oxygen Production Unit air compressors operate on back pressure turbines. There are no proven 2400 psig back-pressure

6.7.1.2 (Continued)

turbine drivers, and the 2400 psig case Oxygen Production unit air compressors have 600 psig condensing turbine drivers. This change increases capital cost for the 2400 psig plant case Oxygen Production unit and Power Generation unit. A significant advantage for the 2400 psig case would be present if the compatible back-pressure turbine becomes available.

6.7.1.3 SCOPE OF WORK

This study evaluates two steam pressure level systems for the Crow Tribe Synfuels Project to determine capital and operating costs, utility requirements and net power generation. The study compares the two systems based on information received from licensors and Fluor in-house data.

The two systems evaluated are:

1500 psig boiler plant based on 40% fines, Westmoreland coal (Base Case)

2400 psig boiler plant based on 40% fines, Westmoreland coal

The units which are impacted as to capital cost and operating requirements by the change in steam pressure level are: Unit 40 - Oxygen Production, Unit 41 - Steam Generation and Unit 42 - Power Generation. Impacts to other units are considered insufficient for inclusion in this study.

6.7.1.4 CRITERIA, RATIONALE, AND ASSUMPTIONS

Feed

The coal feed to each boiler plant is based on 40% fines or 7200 T/D (as received) of Westmoreland coal. Analysis of Westmoreland coal is as follows:

Proximate (As Received)		Ultimate (Dry, Ash Free)	
Moisture	26.0%	Carbon	75.98%
Ash	7.4%	Hydrogen	4.59%
Fixed Carbon	40.1%	Nitrogen	1.09%
Volatiles	26.5%	Sulfur	1.23%
	100%	Chlorine	0.03%
		Oxygen	17.08%
			100%

Heating Value 12,931.4 Btu/lb (DAF)

Based on the analysis of Westmoreland coal, a boiler thermal efficiency of 85% is expected for each system in the conversion of coal to raise steam.

	1500 psig	2400 psig
Treated Water		
Boiler plant makeup	392 gpm	387 gpm
Products		
Boiler Blowdown	23 gpm	18 gpm

6.7.1.4 (Continued)

	1500 psig	2400 psig
Ash		
Fly Ash	35,520 lb/hr	35,520 lb/hr
Bottom Ash	8,800 lb/hr	8,800 lb/hr
Steam Generation		
1500 psig/925°F	4.12 MM lb/hr	
2400 psig/1000°F		4.20 MM lb/hr
600 psig/760°F Reheat Steam	4.12 MM lb/hr	3.93 MM lb/hr
Power Generation	405.0 MW	440.9 MW
Utilities Required		
Power	44.1 MW	49 MW
Cooling Water	172,400 gpm	165,300 gpm

6.7.1.5 CONTENTS AND RESULTS

1500 PSIG Boiler Plant (Base Case)

The Westmoreland Coal, 40% Fines, SNG Case includes the 1500 psig boiler plant in its base design. The 1500 psig steam configuration is shown in Figure 6.7.1-1. BFW at 430°F enters the boilers and is converted to 1500 psig/925°F steam. The steam generated is used to drive air compressors in the Oxygen Production Unit 40 and to raise power in the back-pressure section of the turbogenerators located within the Power Generation Unit 42. The air compressor turbine drivers and the back-pressure section of the turbogenerators exhaust at 650 psig/710°F. This exhaust steam is reheated in the boilers to product 600 psig/760°F steam. A major portion of the reheat steam is used in the LP section (condensing) of the turbogenerators to produce additional power. The balance of the 600 psig/760°F steam is used for process plant makeup. The LP sections of the turbogenerator have seven steam extraction ports. These extraction ports are used for BFW preheating and BFW deaeration. Cooling water is used in the Power Generation unit to condense the exhaust steam from the LP section of the turbogenerators. The steam condensate is polished and reused as BFW. The BFW is preheated to 180°F using extraction steam before entering the deaerator. Once deaerated, the BFW is pumped to 1930 psig and preheated to 430°F using extraction steam prior to entering the boilers.

2400 PSIG Boiler Plant

The 2400 psig boiler plant is similar in design to the 1500 psig system, but minor adjustments are made to consume the 2400 psig steam. The 2400 psig steam configuration is shown in Figure 6.7.1-2.

FIGURE 6.7.1-1
1500 PSIG STEAM CONFIGURATION

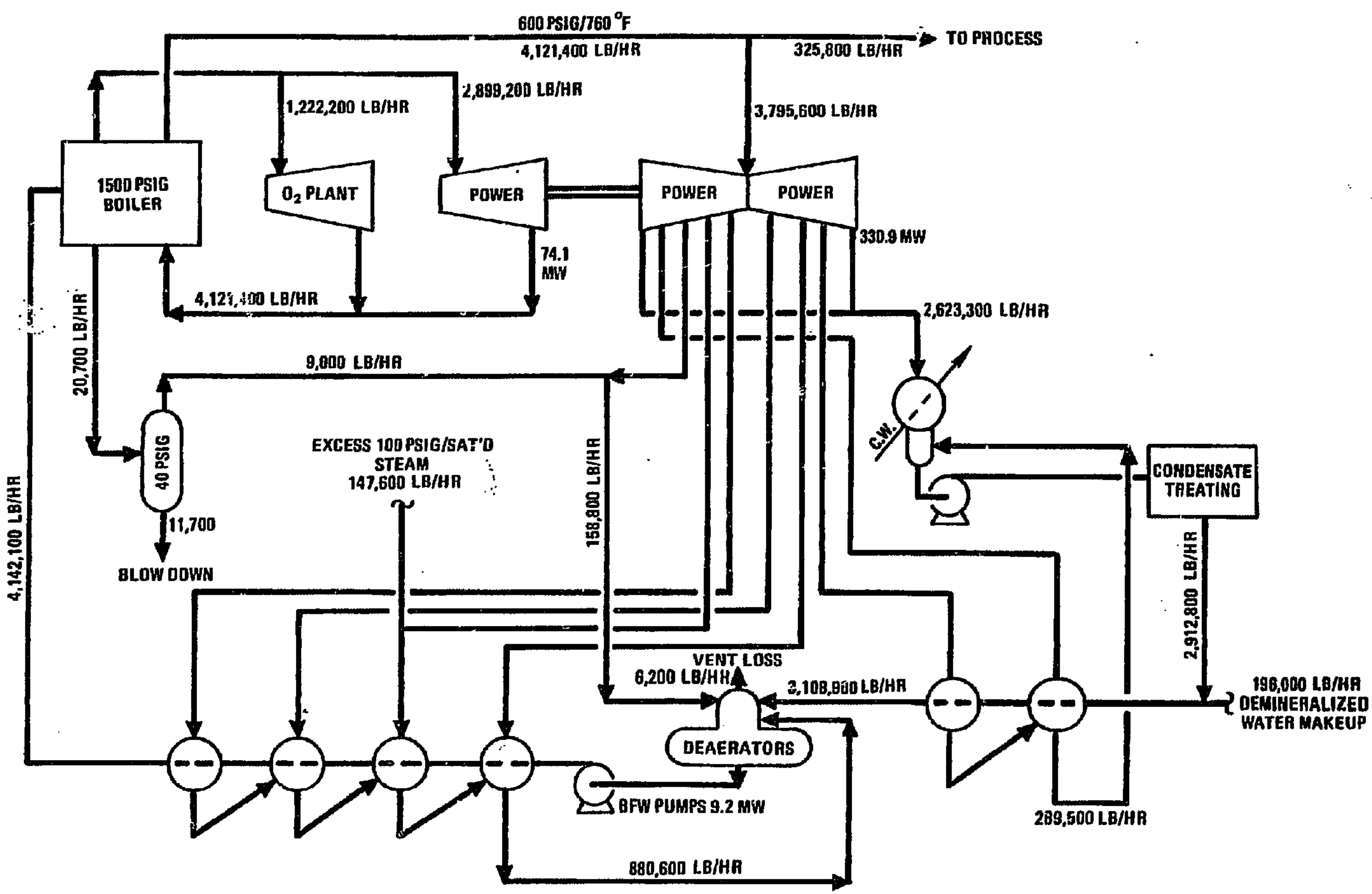
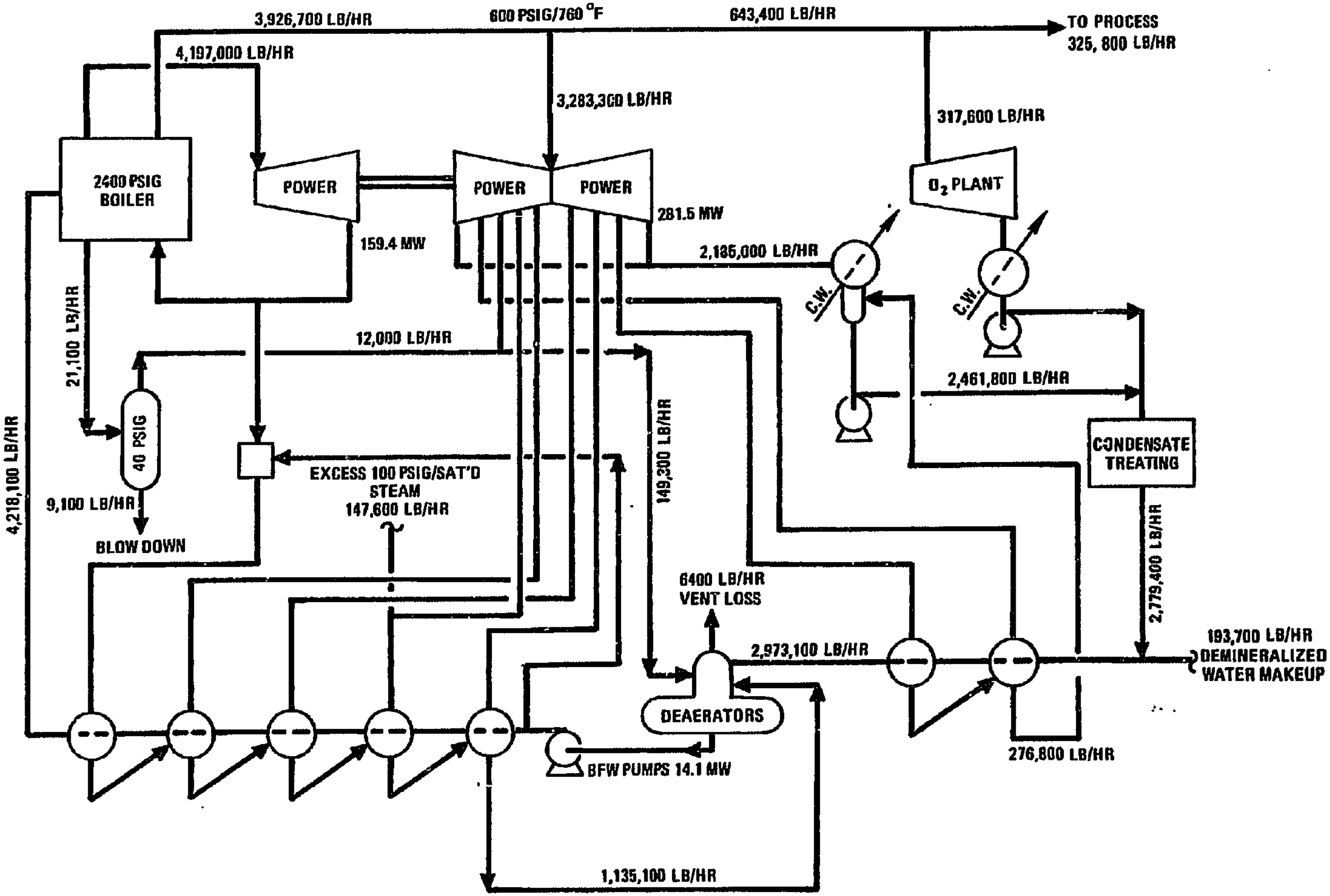


FIGURE 6.7.1-2

2400 PSIG STEAM CONFIGURATION



6.7.1.5 (Continued)

BFW at 480°F enters the boilers and is converted to 2400 psig/1000°F steam. The steam generated is used only in the back-pressure section of the turbogenerators. The air compressor turbine drivers can not use the 2400 psig steam due to the lack of availability of mechanical drivers at this pressure. The air compressor drivers are condensing turbines using 600 psig/760°F reheat steam. The back-pressure section of the turbogenerators exhaust at 650 psig/670°F. A portion of this steam is desuperheated and used for BFW preheating. The balance of the 650 psig/670°F steam is reheated in the boilers to produce 600 psig/760°F steam. A major portion of the reheated steam is used in the LP section (condensing) of the turbogenerator and the air compressor condensing turbines as mentioned earlier. The balance of the 600 psig/760°F steam is used for process plant makeup. The LP sections of the turbogenerators have seven steam extraction ports. These extraction ports are used for BFW preheating and BFW deaeration. Cooling water is used in the Power Generation unit and Oxygen Production unit to condense exhaust steam from the LP section of the turbogenerators and condensing turbines. The condensate streams are combined and polished to be used as BFW. The BFW is preheated using extraction steam to 180°F before entering the deaerator. Once deaerated, the BFW is pumped to 2940 psig and preheated, using extraction steam and desuperheated HP section exhaust steam, to 480°F prior to entering the boilers.

Significant Differences in Systems

The 2400 psig boiler plant has the following significant differences from the 1500 psig boiler plant:

6.7.1.5 (Continued)

BFW pumps require more electrical power because of higher discharge pressure.

An additional BFW exchanger is required to raise BFW from 430°F to 480°F.

A steam desuperheater is required to allow HP turbine exhaust steam to be used for preheating the BFW to 480°F.

Air compressor drivers are condensing turbines instead of high pressure back-pressure turbines.

Air compressor drivers require cooling water and condensate pumps. Overall cooling water load decreased slightly due to a lower amount of steam passing through the condensing section of the power turbine drivers.

Economic Results

The cost information is summarized in Table 6.7.1-1 which lists the direct field costs, catalyst and chemical costs, and total project-capital costs for the two steam systems.

The Oxygen Production Unit 40 in the 2400 psig steam system has a direct field cost $9.8 million greater than in the 1500 psig steam system. The oxygen production unit in the 2400 psig steam system requires the use of 600 psig condensing turbines plus ancilliary equipment to drive the air compressors. The air compressor drivers are back pressure turbines which utilize the 1500 psig steam. The cost of the back pressure turbines are significantly lower than the condensing turbines.

TABLE 6.7.1-1

COST SUMMARY

Unit No.	Name	U.S. $ x 10³ 1500 psig	2400 psig	Cost Increase for 2400 psig
40	Oxygen Production	35,069	44,873	9,804
41	Steam Generation	163,033	176,274	13,241
42	Power Generation	92,414	102,712	10,298
Total Direct Field Cost		290,516	323,859	33,343
Chemicals (Units 40, 41 and 42)				
	Initial Charge	8.4	8.6	0.2
	Annual	92.8	94.8	2.0
Total Project-Capital Cost		1,540,000	1,584,000	44,000

6.7.1.5 (Continued)

The Steam Generation Unit 41 in the 2400 psig steam system has a direct field cost of $13.2 million greater than in the 1500 psig steam system. The increase in cost is mainly due to the cost of the 2400 psig boilers. Boiler support equipment, such as BFW pumps and BFW preheaters, are also more expensive in the 2400 psig steam system. The major factor effecting the cost of the Steam Generation unit is the cost required for materials to accommodate the higher steam pressure.

The Power Generation Unit 42 produces approximately 9 percent more power in the 2400 psig steam system than in the 1500 psig steam system. The increase in power output capacity increases the direct field cost by $10.3 million.

The difference in total direct field costs for Units 40, 41, and 42 is $33.3 million. The net capital cost difference for the entire process plant is $44 million dollars. The difference in chemical cost for the two systems is insignificant.

The 2400 psig steam system produces 31 MW more than the 1500 psig steam system for an increase in capital cost of $44 million. Using a sale price for electrical power of 4¢/kWh, the 2400 psig steam system has a payout of 4.5 years. Using a payout period of 5 years, the sale price for electrical power has to be 3.6¢/kWh.

6.7.1.6 CONCLUSIONS

The 2400 psig steam system has an advantage over the 1500 psig steam system in power cycle efficiency. The 2400 psig steam system, however, is penalized by the fact that mechanical drivers in the Oxygen Production unit can not utilize the 2400 psig steam. Prototype designs of these drivers at this pressure level have been developed but are not in commercial operation at this time. A more detailed evaluation should be considered when these mechanical drivers become available.

6.7.1.6 (Continued)

The 2400 psig boilers have a definite advantage over the 1500 psig boiler in steam production capacity. The 1500 psig boilers, due to the density of steam at this pressure, have a boiler drum size limitation. The maximum design capacity for a 1500 psig boiler is approximately 2.5 MM lb/hr of 1500 psig steam. The 2400 psig steam because of its higher density does not have this limitation. Fewer boilers would be required to produce steam at 2400 psig than the same amount of steam at 1500 psig. In this study, the steam production rate is not large enough to change the number of boilers to benefit from the advantage of using 2400 psig steam. The 2400 psig boilers could be a significant way to decrease the cost of the steam generation unit if a larger size plant is considered.

To accommodate the 2400 psig steam pressure level, the capital cost of the Oxygen Production Unit 40, Steam Generation Unit 41 and Power Generation Unit 42 increased by $44 million. Operating cost and maintenance are essentially the same for both cases. The increases in capital cost is offset by the increase in power of approximately 9 percent or 31 MW.

The conversion to 2400 psig steam did not significantly change the chemicals required for BFW treating. Condensate makeup and boiler blowdown are essentially the same. Because of the same feed rate of the boilers, the coal distribution equipment, ash equipment, and flue gas desulfurization for both cases are identical.

Within the accuracy of this steam study, the 2400 psig steam system is a viable alternative to the 1500 psig system used in the Base Case design.

During the next phase of the Crow Synfuels Project the 2400 psig steam generation system should be compared to the 1500 psig steam system in greater detail.

6.7.2 FLUE GAS DESULFURIZATION

6.7.2.1 INTRODUCTION

Environmental regulations limit the amount of sulfur that may be emitted to the atmosphere. Flue Gas Desulfurization (FGD) is used to reduce the Crow Tribe of Indians Synfuels Plant sulfur emissions to an allowable level.

FGD processes vary in capital and operating costs (for a given flue gas quantity) based on inlet sulfur content and desired sulfur removal. A study comparing three FGD processes was made for the synfuels plant.

This is a preliminary cost study of competing Flue Gas Desulfurization processes. Recovery of byproducts for sale was not considered, even though the licensors could provide designs which would produce saleable byproducts. Capital cost estimates reported elsewhere in this study are based on Fluor in-house data, however, licensor capital cost estimates, operating requirements, and unit efficiencies were used here. The operating requirements, as well as the FGD unit efficiencies were not adjusted by Fluor, but the licensor capital cost estimates were adjusted to put the scope of supply for the FGD units on the same basis. The adjusted capital requirement for each process is not accurate enough to determine the ranking of the processes for this application. A more detailed comparison will be required to make a recommendation for process selection.

The study was based on Westmoreland coal as plant feed and the Base Case plant configuration[1].

(1) The Base Case feeds 60 percent of the coal to Lurgi gasifiers and 40 percent to coal fired boilers. The plant produces 125 MM SCF/CD substitute natural gas (SNG) and byproduct naphtha, sulfur, ammonia and electrical power.

6.7.2.2 SUMMARY

Flue gas desulfurization is required to reduce the sulfur emissions from the coal-fired boiler plant in the synfuels facility. A comparison of three processes was made. The FGD unit economics were evaluated and are summarized in Table 6.7.2-1. Technical considerations included: waste handling and disposal, FGD process licensor's commercial experience and SO_2 removal efficiency. All wet scrubbing processes were judged equal based on the level of effort and accuracy of the study. A more detailed comparison is recommended for the next phase of work. The Davy McKee Saarberg-Hoelter process was arbitrarily selected for use in the Base Case and alternate case studies.

6.7.2.3 SCOPE OF WORK

The processes considered in this study were: Davy McKee's Saarberg-Hoelter, FMC's Double Alkali, and Niro Atomizer/Joy Manufacturing's Dry Scrubbing. Each licensor was asked to provide technical and economic data for a 90 percent SO_2 removal case. Additionally, each was asked if an SO_2 removal efficiency greater than 90 percent was achievable and, if so, to provide the impact on capital and operating costs.

The licensor responses were evaluated on economic and technical merits. Capital and operating costs were compared. Handling and disposal of the waste sludge, commercial experience, and SO_2 removal efficiency were considered.

6.7.2.4 CRITERIA, RATIONALE, AND ASSUMPTIONS

An inquiry document specifying services required was prepared and transmitted to each process licensor. A copy of a typical inquiry is attached. (See Appendix A)

TABLE 6.7.2-1

ECONOMIC SUMMARY

Licensor Process	Davy McKee Saarberg-Hoelter	FMC Double Alkali	Niro Atomizer Niro/Joy
Adjusted Capital Cost[1]	$30,000,000	$36,200,000	$46,040,000
Annual Operating Cost	$ 4,425,000	$ 4,186,000	$ 3,989,000

(1) Capital cost provided by licensors was adjusted by Fluor to the same basis as discussed in "Capital Cost" in this section.

6.7.2.4 (Continued)

Boiler Plant Configuration

Boiler plant/FGD configurations are shown schematically in Figure 6.7.2-1 and 6.7.2-2. Three coal-fired boilers are provided. Normally, the three boilers each operate at one third of the total unit capacity. However, each boiler is designed to operate at 50 percent of the total unit capacity. Two particulate removal schemes can be accommodated. Electrostatic precipitators in the boiler plant are utilized with the wet scrubbing FGD processes. Baghouses are incorporated in the dry FGD process. Flue gas pressure entering and leaving the FGD unit is assumed to be zero inches water. Each licensor was to provide a booster fan sufficient for its process.

Coal

Westmoreland coal is used for the study. The analysis is given in Table 6.7.2-2. The feed rate to the boiler plant is 6,960 ton/day (as received basis); based on a preliminary feed rate assigned at the start of this study.

Flue Gas

The flow rate, composition, and conditions of the flue gas to be treated in the FGD unit are given in Table 6.7.2-3.

6.7.2.5 CONTENTS AND RESULTS

Process Descriptions

The two wet scrubbing processes - Davy S-H and FMC Double Alkali - require that particulates in the boiler flue gas are removed prior to the

FIGURE 6.7.2-1
BOILER PLANT/FGD CONFIGURATION
WET SCRUBBING SYSTEM

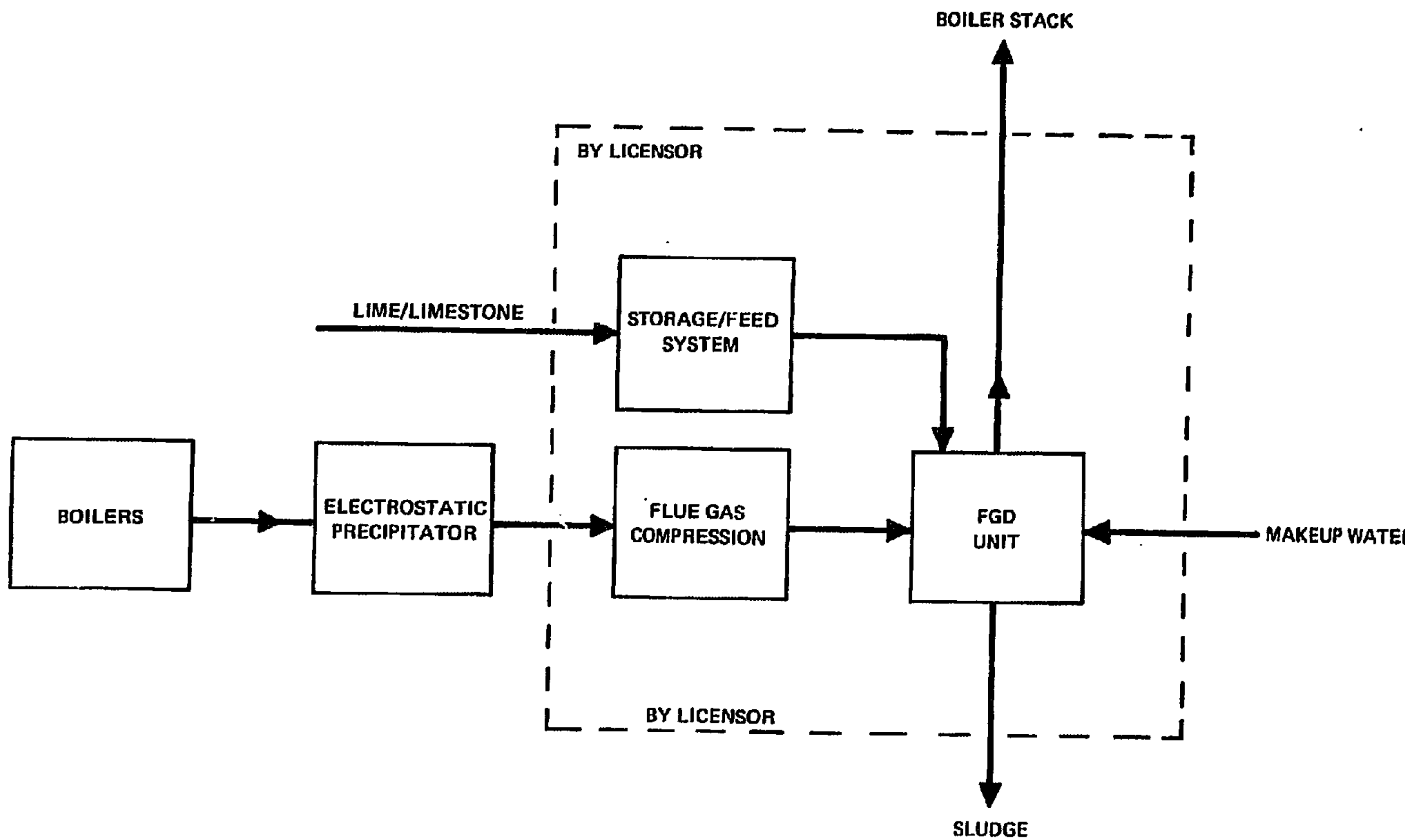


FIGURE 6.7.2-2
BOILER PLANT/FGD CONFIGURATION
DRY SCRUBBING SYSTEM

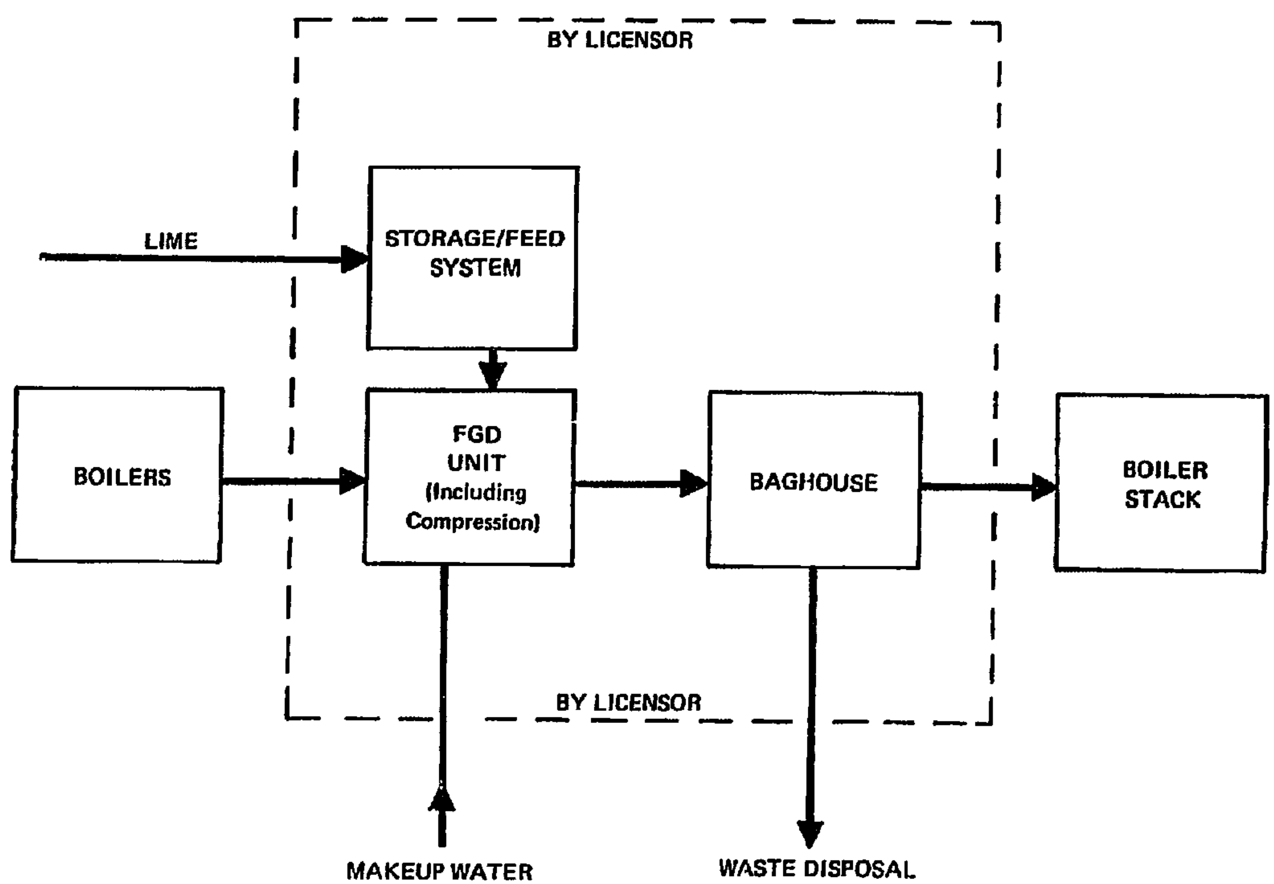


TABLE 6.7.2-2

WESTMORELAND COAL ANALYSIS

Proximate Analysis (wt %)	As Received AR	Dry, Ash Free DAF
Moisture	26.0	-
Ash	7.4	-
Volatile	26.5	-
Fixed Carbon	40.1	-
	100.0	

Ultimate Analysis (wt %)		
Carbon		75.98
Hydrogen		4.59
Nitrogen		1.09
Sulfur		1.23
Chlorine		0.03
Oxygen		17.08
		100.00

Calorific Value (Btu/lb)		
HHV		12,931.4

TABLE 6.7.2-3

FLUE GAS

Flue Gas Flow Rate: Maximum 91,400 lb-mole/hr/boiler
Normal 60,933 lb-mole/hr/boiler

Flue Gas Temperature: 300°F
Flue Gas Pressure: 0.0 in. w.g.

Flue Gas Composition:

Component	Mole %
O_2	4.27
N_2	71.64
CO_2	13.37
H_2O	10.61
	ppmv
HCl	18
NO_2	297
SO_2	811
Particulate	0.014 gr/scf(1)

(1) For wet scrubbing processes only. For the dry scrubbing process the flue gas contains 34,200 lb/hr fly ash.

6.7.2.5 (Continued)

FGD process. The Niro/Joy dry system utilizes flue gas directly from the boiler and incorporates particulate removal and sulfur removal.

Davy S-H

The Davy S-H FGD process is a wet scrubbing process based on lime. The process has four main steps: SO_2 absorption, oxidation, lime addition, and solids separation.

The flue gas is contacted co-currently with the washing solution. Calcium ions in the form of calcium hydroxide, $Ca(OH)_2$, calcium formate, $Ca(COOH)_2$ and calcium chloride, $CaCl_2$, in a clear solution are used to absorb sulfur dioxide from the flue gas. The absorbed SO_2 reacts to form calcium bisulfite, $Ca(HSO_3)_2$, which is water soluble.

In the oxidizer, oxygen is air blown through the solution and converts bisulfite ion, HSO_3^-, to calcium sulfate dihydrate (gypsum) crystals. The scrubbing fluid overflows from the oxidizer into the mixing channel.

Lime slurried in water, $Ca(OH)_2$, is added to the scrubbing fluid in the mixing channel. Lime is added to replenish calcium ions consumed by the formation of gypsum in the oxidizer and to adjust the pH value to that required for SO_2 absorption. A small amount of formic acid is also added to the solution.

The gypsum crystals formed in the oxidizer and mixing channel are separated from the washing fluid in the thickener. The crystals are pumped from the bottom of the thickener to a vacuum filter. The vacuum filter produces a gypsum cake containing approximately 77 percent solids (23 percent free H_2O). The filtrate is recirculated to the thickener. The clear overflow from the top of the thickener is returned to the absorber as washing fluid.

6.7.2.5 (Continued)

FMC Double Alkali

In the FMC Double Alkali process, SO_2 is absorbed in a sodium scrubbing solution and converted to a solid, disposable material by reaction with lime to form a calcium sulfite precipitate. The process consists of a sulfur dioxide absorption section and a sodium regeneration section.

Sulfur dioxide in the flue gas is absorbed by the recirculating process liquor. The absorbed SO_2 reacts with sodium sulfite in the liquor to form sodium bisulfite, $NaHSO_3$. A bleed stream containing $NaHSO_3$ proportional to the amount of SO_2 collected in the absorber is taken from the recirculation stream and sent to the regeneration section.

In the sodium regeneration section the bleed stream is mixed with a slurry of calcium hydroxide, $Ca(OH)_2$. The sodium bisulfite in the process liquor reacts with calcium hydroxide to form calcium sulfite, $CaSO_3$ and sodium sulfite, Na_2SO_3. The calcium sulfite precipitates and flows to a thickener. The thickener bottoms is filtered producing a filter cake of approximately 55 wt% solids. The solution containing regenerated sodium sulfite is returned to the absorption section for further SO_2 removal.

Niro/Joy Dry Scrubbing

The Niro/Joy FGD process utilizes spray drying and produces a dry, free-flowing end product. Lime slurry is used as the absorbing medium.

Hot, untreated flue gas from the boilers is introduced into the spray dryer absorber via the gas disperser. The gas contacts a fine mist of alkaline feed slurry which is atomized by the rotary centrifugal atomizer. Sulfur dioxide is absorbed into the alkaline droplets, and water is simultaneously evaporated. A portion of the dry product, consisting of fly ash, calcium

6.7.2.5 (Continued)

sulfite/sulfate and unreacted lime, falls to the bottom of the absorption chamber and is recycled to the recycle material bin.

The treated gas flows to a baghouse where the remaining suspended solids are removed before the gas exits to the stack. Solids collected in the baghouse are conveyed to the disposal silo or to the recycle material bin.

Recycle material is metered into the recycle slurry tank with dilution water to form the recycle slurry. Excess recycle material is conveyed to the disposal silo. The recycle slurry overflows into the feed tank.

Economic Considerations

The economic considerations for the 90 percent SO_2 removal case are summarized in Table 6.7.2-4. A net present worth analysis is attached as Appendix B.

Capital Cost

The capital costs provided by the licensors were adjusted by Fluor to a common basis. A cost for booster fans needed to provide pressure through the FGD process was added to the capital costs as necessary.

The Niro/Joy system was adjusted for cost for the electrostatic precipitators which the other FGD systems require as part of the boiler plant but are replaced by baghouses in the Niro/Joy system.

The capital costs of the three wet scrubbing processes were essentially equal. All wet processes have lower capital costs than that of the dry scrubbing processes. Of the wet scrubbing processes, the Davy S-H process has a slight advantage on an adjusted capital cost basis.

TABLE 6.7.2-4

ECONOMIC COMPARISON (1)

Licensor Process	Davy McKee Saarberg-Hoelter	FMC Double Alkali	Niro Atomizer Niro/Joy
Capital Cost (as quoted)	$30,090,000	$36,200,000	$65,340,000
Adjustments by Fluor			-19,300,000
Adjusted Capital Cost	$30,006,000	$36,200,000	$46,040,000
Annual Operating Cost			
Maintenance (2)	$ 750,000	$ 905,000	$ 1,306,000
Operating Labor (3)	$ 210,000	$ 280,000	$ 350,000
Reagents	$ 1,400,000	$ 1,330,000	$ 1,400,000
Utilities	$ 2,065,000	$ 1,671,000	$ 933,000
Total Operating Cost	$ 4,425,000	$ 4,186,000	$ 3,989,000

NOTES:
(1) Based on boiler coal feed rate of 290 T/hr and 90% SO_2 removal
(2) 2.5% of adjusted capital cost
(3) $35,000 per year per operator

6.7.2.5 (Continued)

Operating Cost

The operating cost of the FGD systems is comprised of the following costs: Maintenance labor and materials, operating labor, chemicals, and utilities (power and makeup water). The annual maintenance cost is 2.5 percent of the adjusted capital cost. The operating labor cost is based on the number of operators specified by the licensors and an annual cost of $35,000 per operator. The chemical costs are based on the consumption specified by the licensors and unit costs from the Chemical Marketing Reporter. Utility costs are assumed to be $0.05/kWh for power and $0.50/1000 gal. for water.

The total operating cost is approximately $4 million per year for each of the FGD processes studied. The processes differ in the components of the operating cost. The maintenance cost is based on a percentage of capital cost giving the Niro/Joy process a significantly higher maintenance cost than that of the other processes. The Davy S-H process shows the lowest operating labor requirement. The Davy S-H process includes one part-time control room operator and one field operator per shift. The FMC Double Alkali process includes two operators per shift. The Niro/Joy process includes two to three operators per shift. When power requirements for particulate removal (electrostatic precipitators or baghouses) are not included, the Niro/Joy process shows the lowest power consumption. The makeup water requirement for each of the processes is nearly the same.

Technical Considerations

The handling and disposal of the waste sludge generated, the licensors' commercial experience and the maximum attainable efficiency of the processes were evaluated.

6.7.2.5 (Continued)

Waste Handling and Disposal

The Davy S-H processes produce a stable gypsum byproduct. The FGD byproduct is disposed of with the boiler ash and gasifier ash. The Davy S-H process includes vacuum filtration for gypsum slurry dewatering.

The FMC Double Alkali process produces a calcium sulfite filter cake. Fixation is not required to provide mechanical stability. However, without fixation the disposal area may require lining if the soil is porous or if the ground water level is high.

The Niro/Joy process produces a dry, free-flowing product which consists of fly ash, calcium hydroxide, calcium sulfite and calcium sulfate. The material to be disposed of is handled in the same manner as boiler fly ash. It is conveyed pneumatically to a silo and removed by conveyor to the disposal site.

Commercial Experience

The Davy S-H process is in commercial use in West Germany.

The FMC Double Alkali process is in commercial use in the United States.

The Niro/Joy process for flue gas desulfurization is based on the spray drying concept which is used extensively in milk, cellulose, and polymer industries. The application of spray drying to flue gas desulfurization was established at the Niro pilot plant in Copenhagen, Denmark. Industrial units for dry scrubbing of boiler flue gases will start up in 1982.

The Crow Synfuels Facility must not impact the Federal Prevention of Significant Deterioration (PSD) regulations for a nearby Class 1 area. Reduction of SO_2 emissions beyond the 90 percent removal level would

6.7.2.5 (Continued)

allow greater flexibility in plant site location. For a given site, lowering the SO_2 emissions would decrease the height required for the boiler stack.

Davy McKee provided detailed information on a sulfur removal case greater than 90 percent. For an additional $2 million in capital cost and $200,000 per year in operating cost, 93.4 percent of the SO_2 in the flue gas can be removed.

The other licensors indicated that a scrubbing efficiency greater than 90 percent could be achieved but did not indicate what the efficiency would be or what the increase in cost would be.

6.7.2.6 CONCLUSIONS

Within the accuracy of this study, none of the processes evaluated has a clear advantage in all respects. An order of magnitude estimate was requested, and for many of the criteria studied, the differences between the processes are slight.

The capital costs of the Davy and FMC processes are nearly the same, and the capital cost of the Niro/Joy process is significantly higher. The operating costs for all of the processes are essentially equivalent.

The Davy and Niro/Joy systems have an advantage over the FMC system in sludge handling and disposal. The Davy and FMC processes are in commercial operation, but the others are not. Commercial installations utilizing the Niro/Joy process for flue gas desulfurization are under construction, and commercial installations using dry scrubbing for other applications are well established.

6.7.2.6 (Continued)

The Davy S-H process is arbitrarily selected for inclusion in the synfuels plant Base Case. It is among those with the lowest cost; it produces a manageable waste sludge; and it is used in commercial installations. However, a more detailed evaluation should be conducted before any of the processes are ruled out.

Using a common cost basis rather than relying on three licensors for cost information might reveal differences in cost which were not apparent in this study. Potential problems with sludge handling and disposal might be resolved during discussions with the licensors.

APPENDIX

APPENDIX A

SPECIFICATION FOR SERVICES TO BE PROVIDED BY FLUE GAS DESULFURIZATION LICENSOR

1.0 GENERAL

This document defines the capacity, feed, product specification, battery limit conditions, and scope of process facilities for a Flue Gas Desulfurization Unit. The purpose of the facility is to reduce, to allowable limits, the SO_2 flue gas emissions from a coal fired boiler plant.

The interface points between the FGD unit and the boiler plant will be downstream of the electrostatic precipitators and upstream of the boiler stack. Boiler plant configuration is shown on Figure A-1.

2.0 DESIGN BASIS

2.1 Design Considerations

2.1.1 The number of FGD trains will be determined by the licensor. Maximum train treating capacity shall not exceed licensor's largest commercially proven FGD unit. One absorption train per boiler shall be provided.

2.1.2 Three 50 percent boilers are being provided. Normal operation is all three boilers at reduced rates equal to two-thirds of maximum production.

2.1.3 Winterization shall be considered in plant design. Minimum temperature for design is -30°F.

APPENDIX A (Continued)

2.1.4 Licensor shall use best current practices for sparing of equipment.

2.1.5 The unit onstream factor shall be specified by the licensor.

2.1.6 Each train will be designed for continuous operation at design production rates. Minimum onstream time before planned shutdown shall be two years.

2.1.7 Flue gas pressure at electrostatic precipitator/FGD unit interface shall be zero (0) inch water. Licensor to supply fan.

2.1.8 Flue gas pressure at FGD unit/boiler stack interface shall be zero (0) inch water.

2.2 Plant Capacity and Feed Streams

2.2.1 Flue Gas

Barometric pressure - 13.0 psia (3400 feet above mean S.L.)

Flue gas rate - 182,800 lb-mol/hr (total normal flow rate for three boilers)
91,400 lb-mol/hr (maximum flow rate for each boiler)
60,933 lb-mol/hr (normal flow rate for each boiler)

APPENDIX A (Continued)

Flue gas temperature - 300°F

Composition -

Component	Mol %
O_2	4.27
N_2	71.64
CO_2	13.37
H_2O	10.61
	ppmv
HCl	18
NO_2	297
SO_2	811

Particulates 0.014 grains/scf

SO_2 removal efficiency required: 90 percent

2.2.2 Makeup Water

Makeup water required for the process is available with the following composition:

Constituent	mg/l as $CaCO_3$
Calcium	185
Magnesium	124
Sodium	190
Potassium	14
Total Cations	513

APPENDIX A (Continued)

Constituent	mg/l as $CaCO_3$
Bicarbonate	164
Carbonate	0
Hydroxyl	0
Sulfate	317
Chloride	27
Nitrates	3
Fluorides	2
Total Anions	513
Iron	0.2
Manganese	0.1
Boron	0.2
Silica (as SiO_2)	13
CO_2 (as CO_2)	9
pH	7.6
TDS	748
Turbidity (JTU)	118
Temperature	Ambient

APPENDIX A (Continued)

2.2.3 Coal

	Westmoreland	
Proximate Analysis (wt %)	AR	DAF
Moisture	26.0	-
Ash	7.4	-
Volatile	26.5	-
Fixed Carbon	40.1	-
Ultimate Analysis (wt %)		
Carbon		75.98
Hydrogen		4.59
Nitrogen		1.09
Sulfur		1.23
Chlorine		0.03
Oxygen		17.08
Calorific Value (Btu/lb)		
HHV	12,931.4	
Boiler Feed (Total)	6,960 ton/day	

2.3 Product Streams

2.3.1 Particulates in flue gas exiting the FGD unit shall be less than 0.014 grains/scf.

2.3.2 Solid materials generated within the unit, be it waste or saleable product, shall be available for transport at the battery limits.

3.0 GENERAL REQUIREMENTS

3.1 The following data should be included in the process package:

Process description

APPENDIX A (Continued)

3.1 (Continued)

Typical process flow diagram (including environmental effluent and emissions diagrams)

Material balance at operating conditions for all feed, product and effluent streams

Utility consumption and production (normal and maximum requirements)

Chemical requirements including initial inventory, annual consumption, cost basis, and recovery value

Buildings/structures recommended for the system

Plot area requirements and simplified plot plan

Estimated annual maintenance cost expressed as a percent of capital investment, or as a direct dollar estimate

Estimated operating labor requirements

Cost estimate based on a U.S. Gulf Coast plant location and constant dollars

Equipment list

3.2 The following utilities will be available as needed:

600 lb Superheated Steam	- 550 psig @ 760°F
600 lb Saturated Steam	- 575 psig @ 480°F

APPENDIX A (Continued)

3.2 (Continued)

150 lb Steam	- 150 psig @ 300°F
50 lb Steam	- 50 psig @ 300°F
Boiler Feed Water	- As required @ 230°F
Condensate Return	- 50 psig @ 300°F
Cooling Water Supply	- 70 psig @ 80°F
Cooling Water Return	- 45 psig @ 110°F
Nitrogen	- 35 psig @ 95°F
Utility Air	- 100 psig @ 100°F
Instrument Air	- 100 psig @ 100°F
Fuel Gas	- 50 psig @ 75°F

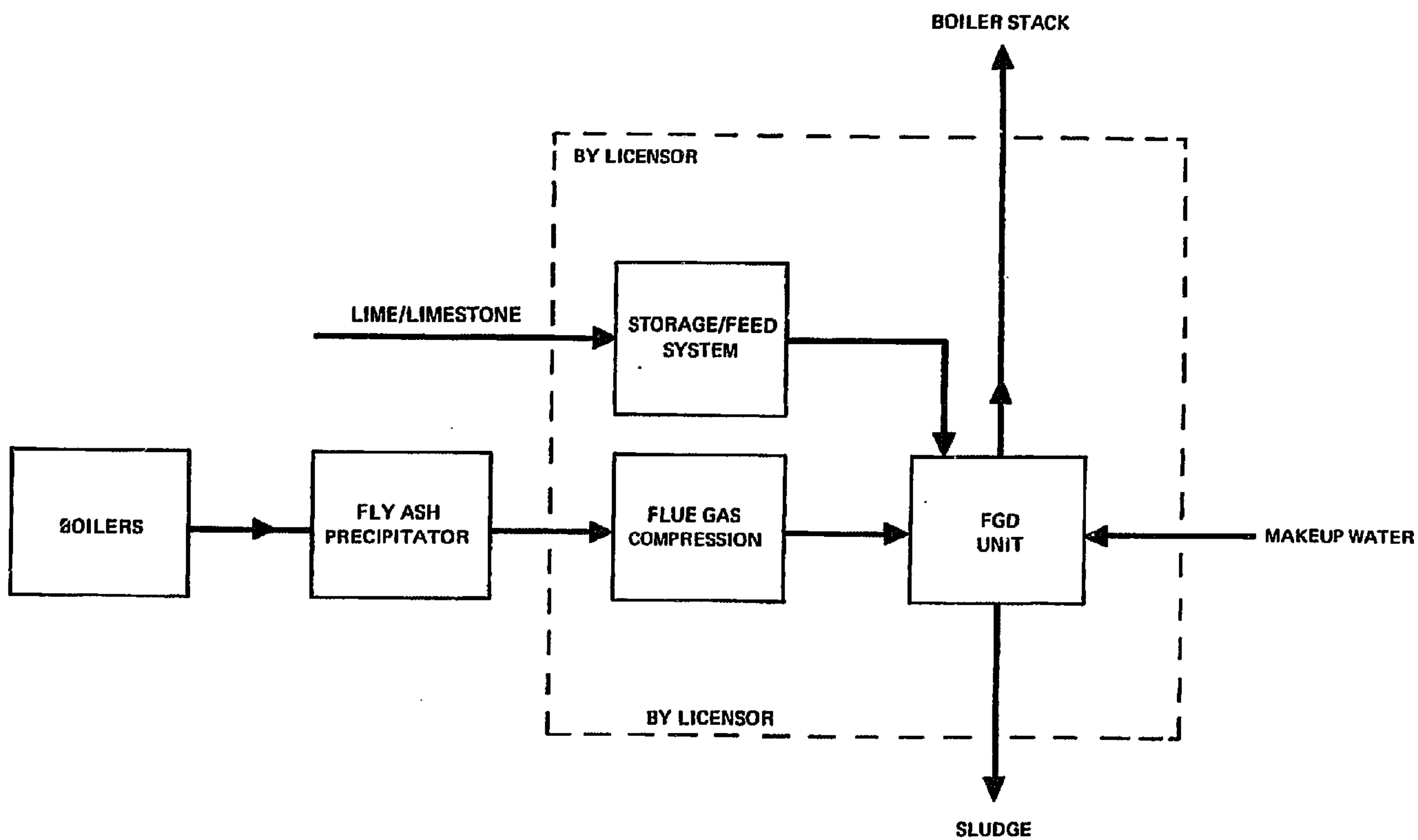
Electrical power is available as required. Power supply voltages are as follows:

Motors above 10,000 BHp	13,800 volts 60 cycles
Motors above 151 BHp	4,000 volts 60 cycles
Motors below 151 BHp	460 volts 60 cycles
Lighting, Instruments, etc.	120 volts 60 cycles

Cooling water fouling factor for design purposes is 0.002 $(Btu/hr\text{-}Ft^2\text{-}°F)^{-1}$.

Design air temperature for air fin exchangers is 88°F. Minimum design process side temperature for air fin exchangers is 115°F.

FIGURE A–1
BOILER PLANT CONFIGURATION



APPENDIX B

NET PRESENT WORTH ANALYSIS

The following analysis was prepared to determine the least costly Flue Gas Desulfurization System. The analysis was performed using the Net Present Worth Method based on the following estimates and assumptions:

PROJECT ASSUMPTIONS

Capital Costs

Case		$ MM
(A)	Davy McKee Saarberg-Hoelter	30.00
(B)	FMC Double Alkali	36.20
(C)	Niro Atomizer Niro/Joy	46.04

Initial Chemical Cost (expensed)

Case		$ MM
(A)	Davy McKee Saarberg-Hoelter	0.137
(B)	FMC Double Alkali	0.120
(C)	Niro Atomizer Niro/Joy	0.127

Drawdown Schedule

1984	5%
1985	15%
1986	40%
1987	30%
1988	10%

APPENDIX B (Continued)

PROJECT ASSUMPTIONS (Continued)

Construction Period: 5 years

Startup Date: January 1, 1989

Project Life: 25 years

Annual Operating Expenses ($ MM)

	Case (A)	Case (B)	Case (C)
Maintenance	0.750	0.905	1.306
Operating Labor	0.210	0.280	0.350
Chemicals	1.400	1.330	1.400
Utilities	2.065	1.731	0.933

Ad Valorem Taxes
and Insurance = 2.5 percent of Total Capital Costs

Taxes

Federal Tax Rate = 46%
State Tax Rate = 6.75%

Tax Depreciation

Five years ACRS - 20%, 32%, 24%, 16%, 8%

APPENDIX B (Continued)

RESULTS

The results are based on a 15 percent discount rate on a non-escalated basis with 1982 as the base year.

Present Worth at 15%[1]

	Case		
	(A)	(B)	(C)
Capital Cost ($ MM)	16.16	19.50	24.80
Operating Expenses ($ MM)	14.01	13.77	13.91
Depreciation Tax Reduction ($ MM)	(4.39)	(5.29)	(6.73)
Operating Cost Tax Reduction ($ MM)	(6.96)	(6.84)	(6.90)
TOTAL ($ MM)	18.83	21.14	25.07

(1) Since no income is shown for this unit, present worth is actually negative; therefore, the lowest value shown is the most favorable.

6.7.3 EXPANDED PLANT STUDY

6.7.3.1 INTRODUCTION

The Crow Tribe of Indians Synfuels Plant is designed to produce 125 million standard cubic feet per calendar day (MM SCF/CD) of pipeline quality substitute natural gas (SNG) from coal. Included in the design is the ability to expand the plant production capacity to 250 MM SCF/CD. Preinvestment cost to facilitate expansion is held to a minimum.

Alternately with an increased preinvestment to facilitate construction expanded plant overall investment is lower.

This study is specific to the Westmoreland Coal 40% Fines - SNG Case at the Site 1 location (the Base Case); however, the plot area requirement for the Shell Coal Case at the Site 23 location is also evaluated for the expanded plant case.

6.7.3.2 SUMMARY

The Westmoreland Coal 40% Fines SNG Case plant located at Site 1 and designed to produce 125 MM SCF/D of SNG can be expanded to produce 250 MM SCF/D of SNG.

A minimum of preinvestment cost is included in the initial plant design to facilitate the expansion.

Feeds, products, byproducts, wastes, utility requirements and catalyst and chemical requirements for the expanded plant are twice that of the Base Case plant.

6.7.3.3 SCOPE OF WORK

This study evaluates the impact of expanding the Westmoreland 40% Fines SNG Case plant at Site 1 from 125 MM SCF/CD to 250 MM SCF/CD. The following areas are considered: Feeds, Products, Emissions, Plot, Train Philosophy, Operating Requirements and Construction.

The plot requirements are also evaluated for the Shell Coal Case at Site 23.

The capital cost of the expanded plant and time period between construction of phase one (Base Case plant) and phase two (expanded plant) are not considered.

6.7.3.4 CRITERIA, RATIONALE, AND ASSUMPTIONS

Design Criteria

The criteria used for this evaluation is to design a plant to produce 125 MM SCF/D of SNG with provisions to be expandable to produce 250 MM SCF/D of SNG. The plant is designed with a minimum of pre-investment for the planned expansion.

The evaluation is made based on the Westmoreland Coal 40% Fines - SNG Case at Site 1.

The plot plan for the Shell Coal at Site 23 is also evaluated.

6.7.3.5 CONTENTS AND RESULTS

Several areas are considered and described in the following paragraphs.

6.7.3.5 (Continued)

Feed, Products, and Emissions

Coal feed to the expanded plant (36,000 T/SD) is twice that for the Base Case plant.

Raw water supply to the expanded plant is twice that for the Base Case plant. The raw water supply line is an area where preinvestment is included to accommodate the expanded plant. A 30-inch diameter pipeline, pumps and ancillary facilities with a 14,000 gpm capacity are included in the Base Case.

Expanded plant production is 250 MM SCF/CD (275 MM SCF/SD), power generated for sale and other byproducts are twice that of the Base Case plant.

For the expanded plant, the emissions to the atmosphere are twice that of the Base Case plant. Atmospheric emissions are the major emissions of concern. During the Base Case design emissions were modeled in terms of the Class I PSD implications for the Northern Cheyenne Indian reservation. Several potential plant sites were eliminated because of sulfur dioxide emissions impacting the Class 1 area.

The Base Case and expanded plants are designed for zero liquid discharge. Solids wastes for the expanded plant are twice that of the Base Case plant and are handled in a similar manner.

The feeds and products for the expanded plant are summarized in Table 6.7.3-1.

Plot Plan

The Base Case plot plan takes into consideration the future expansion of the plant to 250 MM SCF/D.

6.7.3.5 (Continued)

The site preparation work and underground (sewers, etc.) for the expanded plant are included in the 125 MM SCF/D design.

Interconnecting piping and pipe racks for the expanded plant are not included; however, space for expansion of pipe racks is allowed.

Train Philosophy

The train philosophy for the expanded plant with minimum preinvestment is to duplicate the 125 MM SCF/D design with the following exceptions:

Methanol Synthesis	Unit 21	no additional capacity installed
Steam Generation	Unit 41	two new boilers installed instead of three new boilers

The train philosophy for minimum preinvestment is shown in Tables 6.7.3-2a and 6.7.3-3b.

If some additional preinvestment is made the number of trains for several units are reduced; also the plant overall plot requirement is reduced. The train philosophy for the expanded plant with additional preinvestment is shown in Tables 6.7.3-2a and 6.7.3-3b.

Operating Requirements

Operating manpower for the expanded plant increases to 690 from 413 for the Base Case. Operating manpower and materials cost is $26.6 million per year increasing from $16.0 million for the Base Case.

Annual maintenance costs for the expanded plant increase to $63.2 million from $36.1 million for the Base Case. The materials/manpower cost split remains at 60 percent materials and 40 percent manpower. Maintenance manpower is 723.

6.7.3.5 (Continued)

Catalyst and chemicals initial and annual quantities and costs for the expanded plant are twice that for the Base Case.

Utility requirements are twice that for the Base Case.

Construction

The plot area was increased as necessary to allow for construction of the expanded plant with the first phase (Base Case plant) in operation. A shutdown of the initial plant is required for making tie-ins for the expanded plant; however, this shutdown is of brief duration.

The time between first and second phase construction is not considered in this study, but it is anticipated a minimum of two years of initial plant operating experience will be achieved before the expanded plant construction is begun.

Capital Cost

The capital cost evaluation for the expanded plant was not a part of the feasibility study.

6.7.3.6 CONCLUSIONS

Expansion of the Westmoreland Coal 40% Fines SNG Case plant located at Site 1 from 125 MM SCF/CD to 250 MM SCF/CD is viable. A minimum of preinvestment is included. The preinvestment is not optimized.

TABLE 6.7.3-1

FEED AND PRODUCT SUMMARY[1]

EXPANDED PLANT

	UNITS	QUANTITY
Raw Materials		
Coal from Mine	ST/D	36,000
Lurgi Gasification Feed	ST/D	21,600
Boiler Feed	ST/D	14,400
Bulk Chemicals		
Liquids	ST/D	144
Solids	ST/D	316
Water	Acre-Ft/D	60.2
Products (3)		
SNG	MM SCF/D	275 (2)
Aromatic Naphtha	BPSD	2,702
Anhydrous Ammonia	ST/D	153.6
Sulfur	ST/D	174.4
Methanol	ST/D	-0-
Solid Wastes		
Gasifier Ash (Dry)	ST/D	1,654
Boiler Ash (Dry)	ST/D	1,062
Gypsum	ST/D	774
Plant Refuse	ST/D	100
Raw Water Treatment Sludge	ST/D	40
Spent Catalyst	ST/D	0.04
Biotreating Incinerator Ash and Cooling Tower Sludge	ST/D	60

NOTES:
(1) All quantities per stream day
(2) SNG production equals 250 MM SCF/D calendar day basis
(3) Plant also produces 566.4 MW power for sales

TABLE 6.7.3-2a

TRAIN PHILOSOPHY - EXPANDED PLANT-MINIMUM PREINVESTMENT PROCESS UNITS

Unit		No. of Trains	Criteria[1]
01	Coal Screening	4 x 33%	a-Screening Modules, b
02	Coal Distribution	4 x 50%	b
03	Ash Handling	4 x 25%	b
10	Gasification	28 (24 operating)	a-Mk IV Gasifiers, b
11	CO Shift	4 x 33%	b
12	Raw Gas Cooling	4 x 25%	a-Air Coolers, b
13	Rectisol	4 x 25%	a-Methanol Wash Towers, b
14	Gas Liquor Separation	4 x 25% (Note 2)	b
15	Tar Distillation	4 x 25%	b
16	Naphtha Hydrotreating	2 x 50%	
17	Phenosolvan	4 x 25%	b
18	Ammonia Recovery	4 x 25%	b
19	Sulfur Recovery	4 x 25%	b
20	Process Steam Superheating	4 x 25%	b
21	Methanol Synthesis	1 x 100%	
22	Methanation	4 x 25%	b
23	SNG Purification and Compression	4 x 27-1/2%	a-Compressors, b
24	Partial Oxidation	2 x 50%	a-Gasifier
25	Hydrogen Production	2 x 50%	

NOTES: (1) Criteria for number of trains are as follows:
a-Equipment size limitation
b-Operating and maintenance flexibility

(2) Primary separation of dusty tar is 100% spared

TABLE 6.7.3-2b

TRAIN PHILOSOPHY - EXPANDED PLANT MINIMUM PRE INVESTMENT UTILITY AND OFFSITE UNITS

Unit		No. of Trains	Criteria[1]
40	Oxygen Production	4 x 25%	b
41	Steam Generation	5 x 25%	a-Boilers, b
42	Power Generation	6 x 16-2/3%	b
43	Flue Gas Desulfurization	5 x 25%	b
44	Raw Water Treating	2 x 50%	
45	BFW and Condensate Treating	2 x 50%	
46	Air and Nitrogen	2 x 50%	
47	Process Cooling Water	4 [2]	b
48	Utility Cooling Water	2 x 50%	
49	Potable Water	2 x 50%	
50	Utility Water	2 x 50%	
51	Firewater	2 x 50%	
52	Fuel Gas	2 x 50%	
53	Flare	2 x 50%	b
54	Wastewater Treating	4 x 25%	b
55	Tank Farm and Dispatch	2 x 50%	
56	Sanitary Sewage Treatment	2 x 50%	

NOTES: (1) Criteria for number of trains are as follows:
a-Equipment size limitation
b-Operating and maintenance flexibility

(2) Two 16% capacity trains serve the process units and two 34% capacity trains serve the Power Generation and Tank Farm units.

TABLE 6.7.3-3a

TRAIN PHILOSOPHY - EXPANDED PLANT
PROCESS UNITS

Unit		No. of Trains	Criteria [1]
01	Coal Screening	4 x 33%	a-Screening Modules, b
02	Coal Distribution	2 x 100%	b
03	Ash Handling	2 x 50%	b
10	Gasification	28 (24 operating)	a-Mk IV Gasifiers, b
11	CO Shift	2 x 66%	a-Reactor, b
12	Raw Gas Cooling	4 x 25%	a-Air Coolers, b
13	Rectisol	4 x 25%	a-Methanol Wash Towers, b
14	Gas Liquor Separation	2 x 50% (Note 2)	b
15	Tar Distillation	2 x 50%	b
16	Naphtha Hydrotreating	1 x 100%	
17	Phenosolvan	2 x 50%	b
18	Ammonia Recovery	2 x 50%	b
19	Sulfur Recovery	2 x 50%	b
20	Process Steam Superheating	2 x 50%	b
21	Methanol Synthesis	1 x 100%	
22	Methanation	2 x 50% (Note 3)	a-Reactors, b
23	SNG Purification and Compression	2 x 55%	a-Compressors, b
24	Partial Oxidation	2 x 50%	
25	Hydrogen Production	1 x 100%	

NOTE: (1) Criteria for number of trains are as follows:
a-Equipment size limitation
b-Operating and maintenance flexibility

(2) Primary separation of dusty tar is 100% spared

(3) With additional parallel reactors

TABLE 6.7.3-3b

TRAIN PHILOSOPHY - EXPANDED PLANT

UTILITY AND OFFSITE UNITS

Unit		No. of Trains	Criteria(1)
40	Oxygen Production	3 x 33%	a-Compressors
41	Steam Generation	4 x 33%	a-Boilers, b
42	Power Generation	4 x 25%	b
43	Flue Gas Desulfurization	4 x 33%	b
44	Raw Water Treating	2 x 50%	
45	BFW and Condensate Treating	2 x 50%	
46	Air and Nitrogen	1 x 100%	
47	Process Cooling Water	2 (2)	b
48	Utility Cooling Water	1 x 100%	
49	Potable Water	1 x 100%	
50	Utility Water	1 x 100%	
51	Firewater	1 x 100%	
52	Fuel Gas	1 x 100%	
53	Flare	2 x 50%	b
54	Wastewater Treating	2 x 50%	b
55	Tank Farm and Dispatch	1 x 100%	
56	Sanitary Sewage Treatment	1 x 100%	

NOTE: (1) Criteria for number of trains are as follows:

a-Equipment size limitation

b-Operating and maintenance flexibility

(2) A 32% capacity train serves the process units and a 68% capacity train serves the Power Generation and Tank Farm Units.

6.8 DESIGN PLANS AND DRAWINGS

6.8.1 SITE PREPARATION - SITE 1

6.8.1.1 CLEARING AND GRUBBING

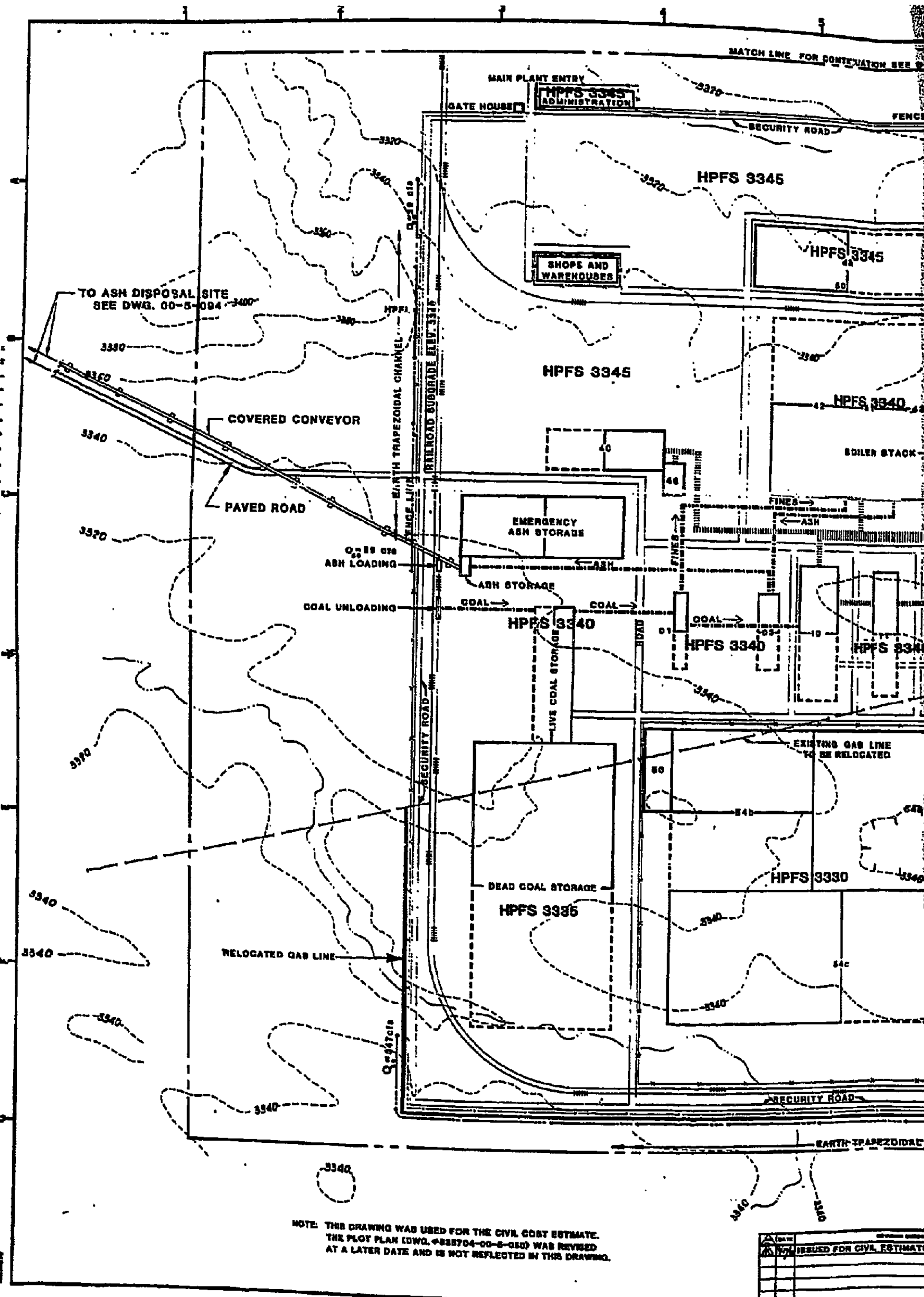
Prior to any excavation operations, the plant site is cleared and grubbed. Most of the area is presently cultivated for dry land wheat farming. Non-cultivated areas have limited vegetation consisting of low lying shrubs and grasses. There are no trees on the plant site area. All organic material is stockpiled and burned or disposed offsite. The clearing and grubbing operations cover an area of 560 acres at a depth of six (6) inches.

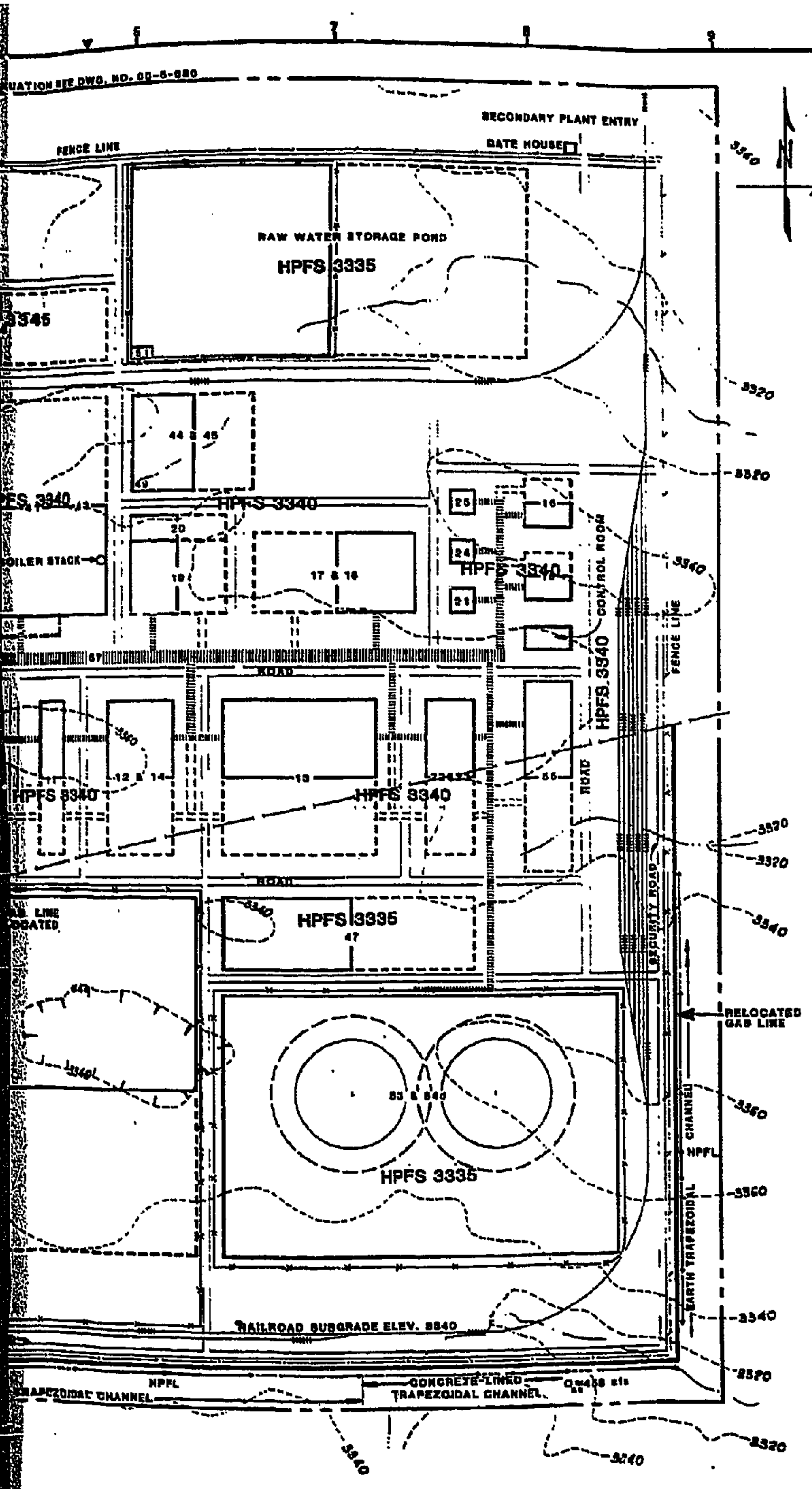
An existing twelve (12) inch diameter, buried gas pipeline runs diagonally across the plant site as described in Section 5.2 Site Data. The pipeline is relocated to run along the western, southern, and eastern sides of the plant site as shown on Drawing 835704-00-5-083.

6.8.1.2 Plant Grading

The plant site is graded to create level areas for the process units as shown on Drawing 835704-00-5-083.

The plant is graded to follow as much as practical the natural terrain of the area thereby minimizing the required earthwork. This necessitates terracing the area and placing some units at different elevations. The terraces step down in the direction of the ponds located in the southern portion of the plant site. The terracing facilitates gravity draining of the process areas to ponds while also minimizing the depth of excavation for drain pipe trenches.


MATCH LINE FOR CONTINUATION SEE
MAIN PLANT ENTRY
HPFS 3345
ADMINISTRATION
GATE HOUSE
FENCE
SECURITY ROAD
HPFS 3345
SHOPS AND WAREHOUSES
HPFS 3345
TO ASH DISPOSAL SITE SEE DWG. 00-5-094
HPFS 3345
HPFS 3340
COVERED CONVEYOR
EARTH TRAPEZOIDAL CHANNEL
RAILROAD SUBGRADE ELEV. 3345
BOILER STACK
PAVED ROAD
FINES
ASH
EMERGENCY ASH STORAGE
ASH LOADING
ASH STORAGE
COAL UNLOADING
COAL
HPFS 3340
HPFS 3340
HPFS 3340
LIVE COAL STORAGE
ROAD
SECURITY ROAD
EXISTING GAS LINE TO BE RELOCATED
HPFS 3330
DEAD COAL STORAGE
HPFS 3335
RELOCATED GAS LINE
SECURITY ROAD
EARTH TRAPEZOIDAL
ISSUED FOR CIVIL ESTIMATE
NOTE: THIS DRAWING WAS USED FOR THE CIVIL COST ESTIMATE. THE PLOT PLAN (DWG. #335704-00-5-050) WAS REVISED AT A LATER DATE AND IS NOT REFLECTED IN THIS DRAWING.



LIST OF UNITS

01	COAL SCREENING
03	ASH HANDLING
10	COAL GASIFICATION
11	CO SHIFT
12	RAW GAS COOLING
13	RECTISOL
14	GAS LIQUOR SEPARATION
15	TAR DISTILLATION
16	NAPHTHA HYDROTREATING
17	PHENOSOLVAN
18	AMMONIA RECOVERY
19	SULFUR RECOVERY
20	PROCESS STEAM SUPERHEATING
21	METHANOL SYNTHESIS
22	METHANATION
23	SNG PURIFICATION & COMPRESSION
24	PARTIAL OXIDATION
25	HYDROGEN PRODUCTION
40	OXYGEN PRODUCTION
41	STEAM GENERATION
42	POWER GENERATION
43	FLUE GAS DESULFURIZATION
44	RAW WATER TREATING
45	BFW & CONDENSATE TREATING
46	AIR & NITROGEN SYSTEMS
47	PROCESS COOLING WATER
48	UTILITY COOLING WATER
49	POTABLE WATER
50	UTILITY WATER
51	FIREWATER
53	FLARES
54a	STORM & OILY WATER
54b	WASTEWATER TREATING
54c	WASTEWATER PONDS
54d	SOLAR EVAPORATION POND
55	TANK FARM & DISPATCH
56	SANITARY SEWER
57	INTERCONNECTING PIPEWAY

LEGEND

HPFL	HIGH POINT FLOW LINE
	FLOW LINE
	PLANT BOUNDARY
3340	EXISTING CONTOUR LINE
HPFS	HIGH POINT FINISH SURFACE
	FENCE LINE
	OVERHEAD PIPEWAY
	CONVEYOR
	RAILROAD
	FUTURE
Q_{50}	50 YEAR STORM
cfs	CUBIC FEET PER SECOND

0 200 400 600 800 1000 FT.

REDUCED PRINT SCALE

USE OR DISCLOSURE OF REPORT DATA IS SUBJECT TO THE RESTRICTION ON THE NOTICE PAGE AT THE FRONT OF THIS REPORT

PLOT PLAN
VICINITY MAP

FLUOR

SITE #1 SITE PREPARATION
OFF-SITE DRAINAGE, GRADING, & RELOCATION PLAN
SYNFUELS FEASIBILITY STUDY
CROW TRIBE OF INDIANS MONTANA

1" = 200'

835704-00-5-083 A

6.8.1.2 (Continued)

The process areas in the center portion of the plant site are located on naturally high ground. This area requires excavation to attain its final grade elevation. The process unit areas and the administration complex in the northern portion of the site are on fill. The railroad facility located along the eastern boundary of the site requires both excavation and fill.

The dead coal storage area in the southwest corner of the plant site is primarily on fill. The ponds in the southern portion of the site which include the storm and oily water ponds and the solar evaporation pond require excavation. The raw water storage pond in the northern portion of the site requires both excavation and fill.

The earthwork quantities of excavation and fill are in balance so that no importing of or exporting of material is required. The quantity of excavation and backfill is approximately 5,000,000 cubic yards each. A 15 percent shrinkage factor was assumed. Naturally soft soils including topsoils that are unsuitable for foundations are improved by mixing with other soils for use onsite.

All permanent slopes are constructed to a slope of 2H:1V or flatter.

Excavation. Excavation of the soil and rock can generally be accomplished with scrapers and bulldozers. The claystone bedrock may require rock ripping equipment. Very little, if any, blasting is anticipated. All excavated soils are suitable for recompaction.

Compaction. Constructing engineered fills with clay soils and bedrock material is accomplished by processing the material into small particles and adjusting the moisture content to near optimum before compaction.

6.8.1.2 (Continued)

Disking or rotovating techniques are used to break these types of materials into small particles and to mix water with them. A kneading type of compactor such as a sheepsfoot roller is used for compacting the clay and claystone materials.

Expansive Soils. Much of clay and claystone soils over the site have expansive characteristics. These clays have a potential to increase in volume (swell) with an increase in moisture, and decrease in volume (shrink) with a decrease in moisture. If this characteristic is not minimized or controlled, the stability of foundations and pavements may become a problem. This problem is further addressed below.

Control of Surface Moisture. Infiltration of surface moisture can be a major factor contributing to moisture fluctuations of the near surface soils and rocks. Surface moisture generally originates from one of three sources: precipitation, watering of vegetation, or leaks in utility lines.

Drainage to control surface moisture, both during and after construction, is essential because of the expansive characteristics of clay soils. Therefore, during construction, the site will have a temporary drainage system to quickly drain the area and prevent any ponding of water. After construction, all plant process areas will be designed with a permanent, rapidly draining system. All plant process unit areas are drained by underground sewer lines to stormwater ponds located in the southerly portion of the site as shown on Drawing 835704-00-5-083. All surfaces within the plant process areas are sloped to catch basins. This allows all storm runoff within the process areas to be routed to and contained in the stormwater ponds. All top layers within the process areas are excavated and recompacted to a minimum of five (5) feet. This densifies the soil to minimize moisture infiltration. All process areas situated in low areas of the plant are raised by compacted fill to minimize both groundwater and surface

6.8.1.2 (Continued)

moisture infiltration. All areas of structures and foundations are paved with either concrete or asphalt to prevent surface moisture seepage. Planting of vegetation that requires watering within ten (10) feet of foundations is not allowed. All snow drifts which restrict site drainage will be removed during construction and plant operation. During operation of the plant, all leaking utility or steam pipes will be promptly repaired.

Offsite Drainage. Runoff occuring offsite of the plant areas is intercepted and diverted away from the plant to existing natural drainage courses as shown on Drawing 835704-00-5-083. This offsite drainage system consists of open channels to transport the storm runoff. No runoff from the plant unit areas is allowed to enter the offsite drainage channels.

As discussed in Section 5.2.7.2, the direction of the natural drainage is generally away from the site. Therefore, the quantities and dimensions of the required drainage channels are limited in size.

The major channel of the offsite drainage system is situated parallel to the southerly plant boundary. This channel intercepts the runoff occurring south of the plant and drains it to the west and east. The high point flow line of the channel is located near its center. A portion of the channel at its easterly end is concrete lined to prevent erosion. This was required because of the high water velocity due to the steep channel slope.

The offsite runoff from a small drainage area near the northwesterly corner of the plant is intercepted by an open channel to protect the road and railroad in the area. The road and railroad along the southernly end of the easternly plant boundary is also protected by an open channel. These channels flow to natural drainages which convey the runoff away form the site.

6.8.1.2 (Continued)

The channels are sized for peak flow rates resulting from a storm with a 50 year return cycle (50 year). The discharge quantities of the channels are shown on Drawing 835704-00-5-083. The rainfall design data is included in Section 5.2.5.

Typical details and a summary of the quantities for the offsite drainage channels are shown on Drawing 835704-00-1-092 and Drawing 835704-00-1-093.

Fencing. The entire perimeter of the plant site is fenced with a chain link-type fence as shown on Drawing 835704-00-2-090. This fence is provided to secure the plant from outside intruders. Fencing is also provided internally to limit access to certain areas within the plant as described below:

All pond areas are fenced to limit access to only authorized personnel and also for the safety of others.

The transformer/switchyard is fenced to prevent access by unauthorized personnel to the high voltage equipment.

The warehouse is fenced to restrict the entrance of personnel and to prevent the unauthorized removal of items and equipment.

The administration and parking area is fenced to prevent visitors from entering the plant facility unescorted.

Personnel gates and vehicle gates are provided as required for entrance to restricted areas.

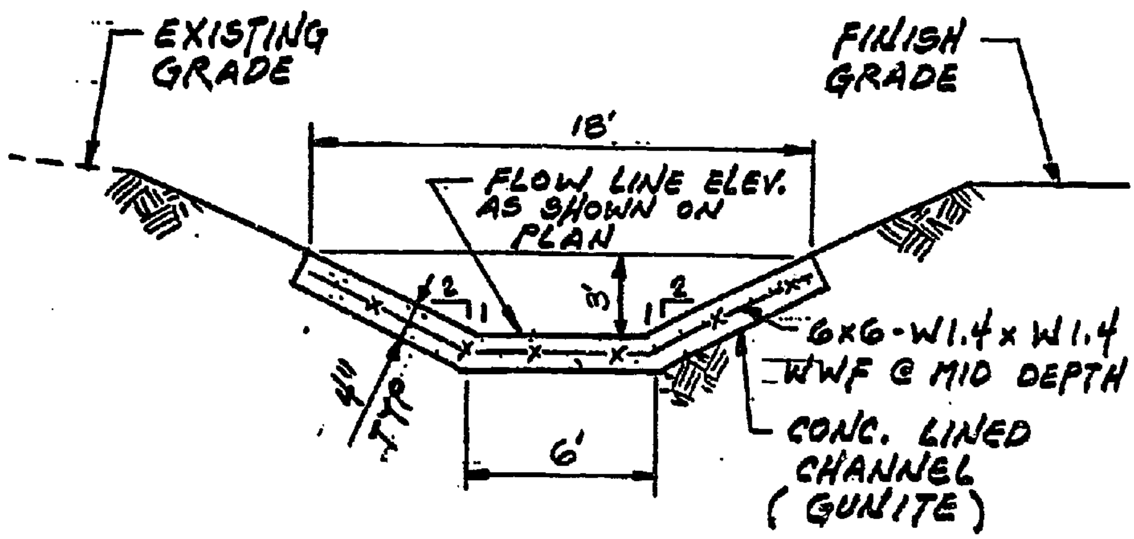
6.8.1.2 (Continued)

The summary of estimated quantities for fences and gates is as follows:

Item	Quantity
8' high chain link fence	42,000 Lineal Feet (LF)
3'-6" wide gate	12 each
32'-0" wide double swing gate	3 each
16'-0" wide single swing gate	9 each

Plot Plan Late Changes

The plot plan of the site was modified at a late date. These changes are not reflected in the civil/structural drawings.



SECTION

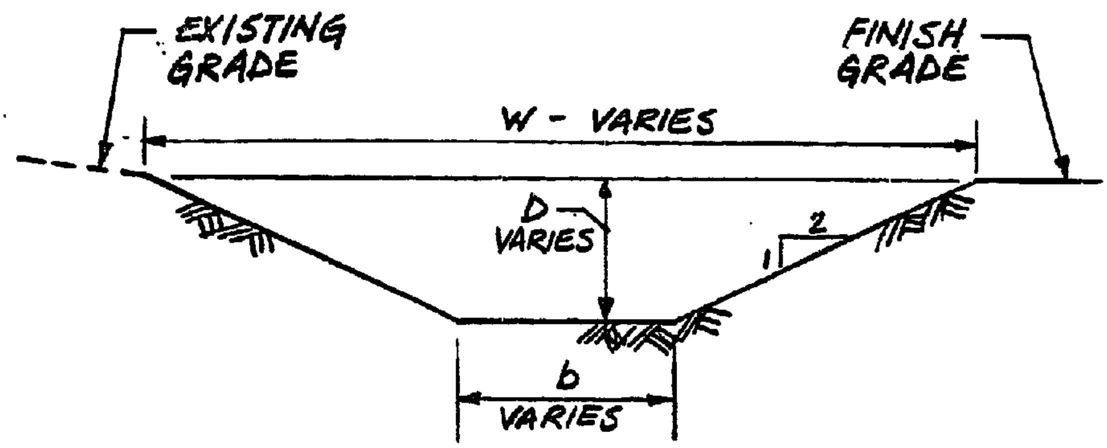
CONCRETE LINED TRAPEZOIDAL CHANNEL

LENGTH: 1,400 FT

SITE #1

FLUOR	DR J. GRAU CH M. DORIN SUPR A. QUINONES PROJ ENG M. DORIN	CONCRETE LINED TRAPEZOIDAL CHANNEL SYNFUELS FEASIBILITY STUDY CROW TRIBE OF INDIANS MONTANA
	SCALE NONE	DRAWING NUMBER 835704-00-1-092 / REV. 1

FORM E-305 REV. 1/73 PRINTED IN U.S.A.



TYPICAL SECTION

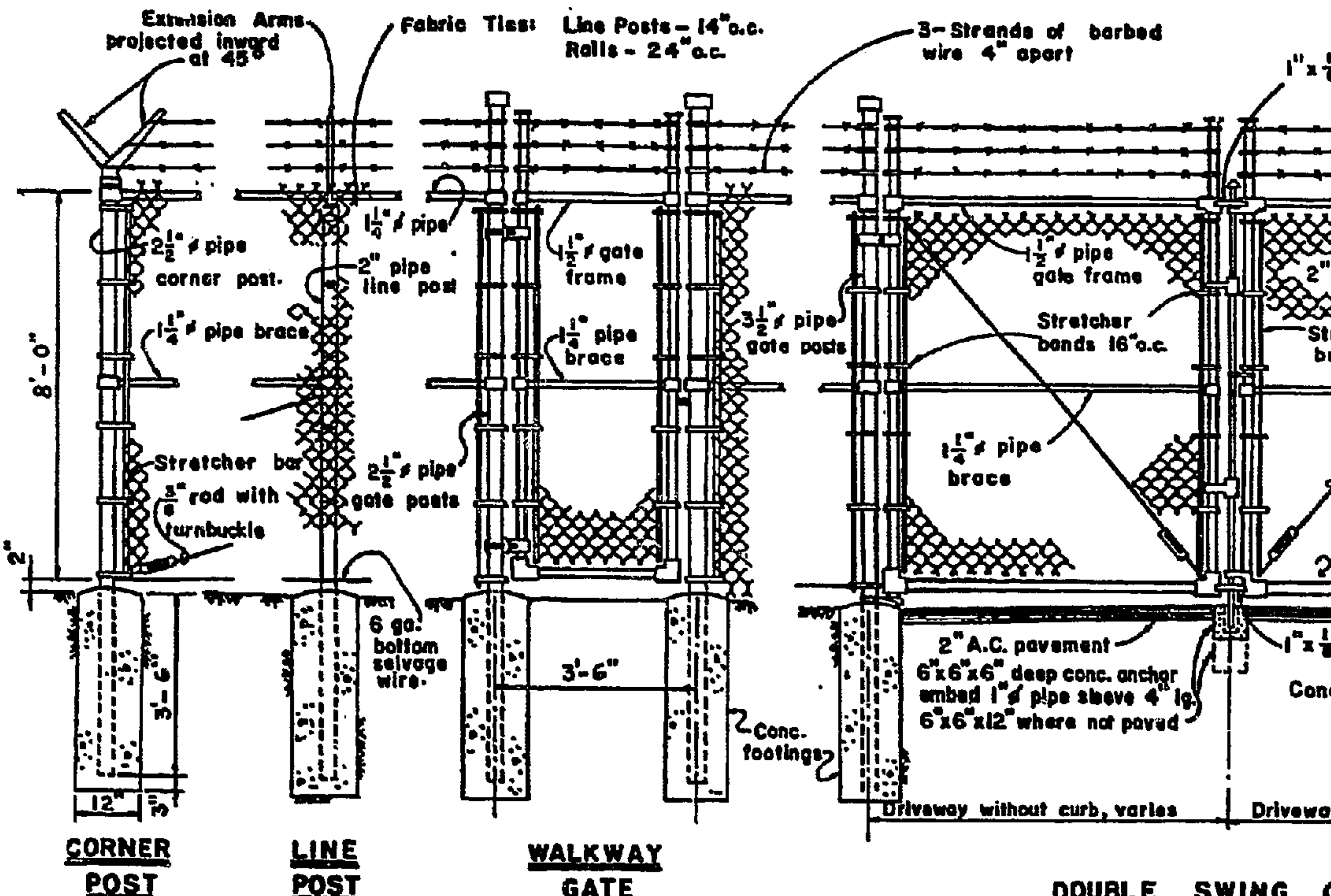
EARTH TRAPEZOIDAL CHANNEL

CHANNEL SCHEDULE			
b (FT)	D (FT)	W (FT)	TOTAL LENGTH (FT)
12	7	40	2300
2	3	14	3600
2	1	6	1800

SITE #1

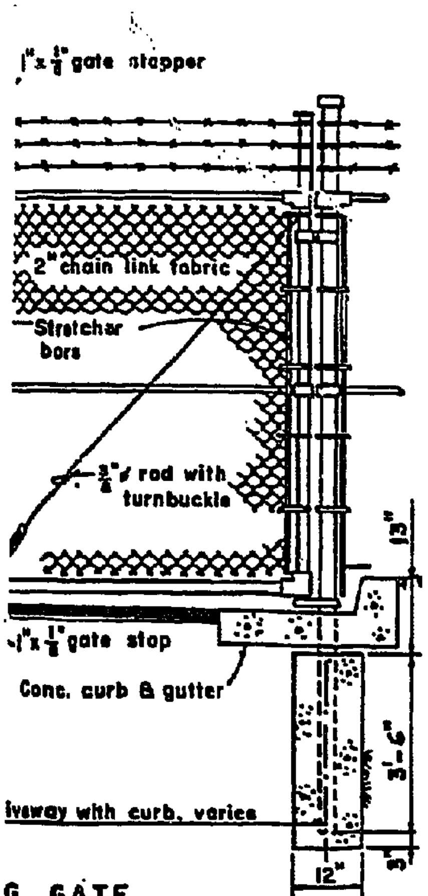
FLUOR

DR J. GRAU	EARTH TRAPEZOIDAL CHANNEL
CH M. DORIN	SYNFUELS FEASIBILITY STUDY
SUPP A. QUINONES	
SUPR ENG M. DORIN	CROW TRIBE OF INDIANS MONTANA
SCALE NONE	DRAWING NUMBER 835704-00-1-093 REV. 1



REV. NO.	DATE	REVISION DESCRIPTION	DRAWN / CHECK	DATE
1	6/9/82	ISSUED FOR STUDY	M.D.	6/9/82

FLUO



G GATE

NOTES

1. Fencing materials shall be galvanized steel
2. Posts, braces, and gate frames shall be schedule 40 (standard weight) pipe. Sizes specified are nominal diameter.
3. Double Swing Gate shall be provided with Tubular Plunger Bar, 1 Lock keeper, 1 Lock Keeper Guide, 2 Latch Forks, 2 Fork Catches, 1 Catch for plunger bar, and 2 Gate Stops located as directed by the Engineer.
4. Walkway Gate shall be provided with Fork Latch assemblies with provisions for padlocking.
5. Padlocks shall be provided for gate locks.
6. Posts, caps and other necessary fence fittings shall be as manufactured by the fence manufacturer or equal except hinges shall be of galvanized steel.
7. Posts shall be spaced equidistant but not more than 10' o.c.

DRAWN BY: M. PIERCE		FENCING DETAILS
CHECKED BY: M. DORIN		SYNFUELS FEASIBILITY STUDY
SUPERVISOR: A. QUINONES	RELEASE DATE: 6/9/82	
SUPERVISING ENGR.: M. DORIN	INITIALS: M. Dorin	CROW TRIBE OF INDIANS — MONTANA
PROJECT: R. LANG	APP. DATE: RAL 6/9/82	SCALE: NONE · DRAWING NUMBER: 835704-00-2-090 · REVISION: 1
CLIENT	APP. DATE	