1 of 2

Environmental Report for the Gasification Product Improvement Facility (GPIF)

Topical Report

**R.S. Sadowski
W.H. Skinner
E.S. Norris
R.R. Duck
R.B. Hass
M.E. Morgan
J.J. Helble
S.A. Johnson**

January 1993

Work Performed Under Contract No.: DE-AC21-92MC28202

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
CRS Serrine Engineers, Inc.
Greenville, South Carolina

MASTER

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Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880**

**By
CRS Sirrine Engineers, Inc.
1041 East Butler Road
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January 1993

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Task 1
Gasification Product Improvement Facility (GPIF)
Environmental, Safety, & Health (ES&H) Information
National Environmental Policy Act (NEPA)

1. Introduction

The Department of Energy (DOE) Fossil Energy Program has a mission to develop energy systems that utilize national coal resources in power systems with increased efficiency and environmental compatibility. Coal gasification technology is a versatile candidate that meets this goal.

Optimized air-blown fixed-bed gasification power generation systems at a cost of about \$1000 per kilowatt (KW) are possible if gasifier subsystem process components can be reduced or eliminated.

This two phased project consists primarily of the design, construction and operation of a 5-foot inside diameter (minimum) fixed-bed gasifier called PyGas™ and supporting infrastructure (Phase I), and an additional follow on phase consisting of the design, construction and operation of a hot fuel gas cleanup unit (Phase II).

2. Project Objectives

The main goal of the GPIF project is to develop systems and subsystems to resolve technological issues that surround the simplified IGCC concept. Issues expected to be successfully overcome by PyGas™ through its application in this test facility include the processing of high-swelling coals, which causes agglomeration in conventional fixed-bed gasifiers. Such coals comprise 87% of all eastern coals. Other issues expected to be eliminated or significantly reduced include: production of ash clinkers, production of ammonia, the presence of significant tars and fines, and the volatilization of alkalinity in the product fuel gas.

3. Schedule of Milestones

Figure 1
Schedule of Milestones
FY93 Program Schedule

6. Technical Approach

The gasifier test facility general arrangement drawing (Figure 2) utilizes the CRS Sirrine Engineers, Inc. proprietary gasification invention nominally rated (for materials handling purposes) at 6 tons per hour coal throughput. Its capacity is therefore anticipated to be approximately six times the capacity of the existing 42 inch diameter METC test gasifier. The operating pressure is 600 psi, and the gasifier is expected to be 5 feet (minimum) in diameter, and some 34 feet in height. It is designed to operate at a maximum coal firing rate of 150-MBtu/hr. Since it will be located at an existing utility site, it is anticipated that the products of combustion from the coal derived gas will be returned to the existing stack.

7. Existing Facility Description

Fort Martin Generating Station (Figure 3 & Table 1) is a 1000 MWe pulverized coal fired electric utility power plant located in Point Marion, West Virginia, some two miles down the Monongahela River from the Morgantown Energy Technology Center. It is operated by Monongahela Power Co., an Allegheny Power System company. High and low sulfur coals are currently blended to meet current sulfur emission limits. Coal is received by barge, conveyed to an enclosed breaker house, and loaded out to either long term or active open coal piles, and reclaimed in a manner that allows the utility to control feed quantities of the low and high sulfur coal feed stocks. Steam turbine condenser heat of condensation is rejected via conventional cooling towers to the atmosphere. Coal ash is pneumatically conveyed to ash silos and subsequently is trucked to a permitted coal ash landfill area on the premises. Care and due diligence is practiced to avoid excessive dusting using water sprays during ash loading onto the ash trucks, and wind screens are in place as a deterrent to wind blown ash from the landfill. Sulfur is currently the only criteria pollutant requiring controlled emission limits. Figure 4 shows a photograph of the existing site with alternate GPIF locations identified.

8. Test Facility Major Equipment Capacities and Ties to Ft. Martin

Included herewith are the process flow sheet (Figure 5) and typical mass balances (Table 2) for the existing Fort Martin Generating Station along with a mass balance predicted for the Gasification Product Improvement Facility (GPIF) under Phases I & II. The numbered columns match the circled numbers identified in the preliminary process flow diagram. Proposed ties to Ft. Martin are identified in Figure 6.

The concept is to fire coal gas in a closely coupled packaged auxiliary steam generator located within the GPIF. The products of combustion will then be ducted back to the existing flue gas duct of Fort Martin Unit #2 upstream of the existing stack. The heat released within the packaged fired auxiliary steam generator will be returned to the existing Fort Martin Unit #2 in the form of steam. As contemplated, the GPIF represents only approximately 1.5% of the full load rated station firing rate, an aliquot side stream of feedwater will be fed to and returned from the GPIF as auxiliary or high pressure steam for the utility company. The new boiler will have a capacity of approximately 90,000 lbs per hour of steam.

In addition to the light oil ignited coal gas fired heat recovery steam generator (HRSG), either a smaller 10,000 lbs per hour steam light oil fired packaged boiler, or equivalent steam from Ft. Martin, vented to atmosphere is contemplated for space heating and gasification process steam.

The limestone feed capability to the PyGas™ coal gasifier may be sufficient in concert with coal gas combustion and steam generation to reduce Fort Martin sulfur emissions from currently

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Richard S. Sadowski
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W. SKINNER
P.E.
W. SKINNER
JAN. NO. 31604
CRSS

CRSS Power Division
Greenville, S.C.
CRS SKIRINE

GASIFICATION PRODUCT IMPROVEMENT FACILITY
DEPARTMENT OF ENERGY

FIGURE 2
GENERAL ARRANGEMENT

31604-001-400

Table 1

FORT MARTIN TOUR ROUTE

Stop 1	Training Room at the Fort Martin Power Station. Tour groups will be formed and introduced to the utility tour guides.
Stop 2	Connection point for Filtered Water. Available at quantities up to 200 gpm for steam generation and general use. Anticipated pressure at connection point is 150 psig.
Stop 3	Connection point for Service Water. Available for fire protection at quantities up to 1200 gpm. Anticipated pressure at the connection point is 85 psig.
Stop 4	Connection point for Potable Water. Plant storage consists of a 20,000 gal tank. Conveyed (by gravity) to plant through a 3-inch PVC line at 15 gpm. Anticipated pressure at connection point is 120 psig.
Stop 5	Approximate location of railroad crossing required for access to the GPIF.
Stop 6	Approximate location of the GPIF, as shown by surveyors stakes. Access during construction and test operations will be via Stop 15 & 5. Approximately four acres.
Stop 7	Existing storage shed to be relocated area near Stop 8.
Stop 8	New location of storage shed presently located on the GPIF site.
Stop 9	Anticipated route of buried GPIF process waste water pipes from the GPIF to the Plant ash settling basins. Plant will provide treatment and discharge.
Stop 10	Plant ash settling basins.
Stop 11	Approximate locale for GPIF fuel gas to enter the Plant for combustion in the coal-fired boiler
Stop 12	Unit #2 coal-fired boiler
Stop 13	Unit #2 Control Room.
Stop 14	Coal storage pile for Plant operations. Low-sulfur coal will be made available for GPIF operations.
Stop 15	Truck weigh station for ash trucks.
Stop 16	Unimproved roadway leading to the railroad crossing and the GPIF site.
Stop 17	Paved road leading to the ash disposal pit, contractors' entrance and exit.

Figure 4
Alternate GPIF Sites
Ft Martin Generating Station
Monongahela Power

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CRSS Power Division Greenville, S.C.

GPIF PROJECT

Figure 5

DRAWING TITLE

PROCESS FLOW SHEET

DRAWING NUMBER

31604-40-F-18P-001

2 DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced)

Table 2.2

3 NEPA Support Document, Mass Balance

*Using FW Data (High Steam - Low Blu) Case

5 Stream No.		6	6a	6b
6 Identification		Combustion Air	Combustion Air	Combustion Air
7 From		Total	Exhaust Vents	Ambient
8 To		HRSO Burner	HRSO Burner	HRSO Burner
9 Gas	Mol Wt	lb/hr		
11 CO	28.010	0	0	
12 H ₂	2.016	0	0	
13 CO ₂	44.010	49	922	4
14 H ₂ O	18.015	652	426	65
15 CH ₄	16.042	0	0	
16 C ₂ H ₆	30.068	0	0	
17 H ₂ S	34.076	0	0	
18 COS	60.070	0	0	
19 N ₂	28.013	76923	11,458	6546
20 Ar	39.948	1347	201	114
21 HCl	36.461	0	0	
22 HCN	27.026	0	0	
23 NH ₃	17.030	0	0	
24 CS ₂	76.131	0	0	
25 SO ₂	64.059	0	3	
26 NO	30.006	0	0	
27 O ₂	31.999	23559	3,270	2028
28 NaCl	58.497	0	0	
29 KCl	74.596	0	0	
30 CaSO ₄	136.142	0	0	
31 Ca(OH) ₂	74.095	0	0	
32 Cl ₂	35.500	0	0	
33 Total Gas (lb/hr)		102529	16,329	8620
66				
67 C	12.011			
68 H	1.008			
69 O	16.000			
70 N	14.007			
71 S	32.060			
72 CaO	56.079			
73 H ₂ O	18.016			
74 NaCl	58.497			
75 KCl	74.596			
76 CaSO ₄	136.142			
77 Ca	40.080			
78 CaS	72.140			
79 ASH, Inerts (pph)				
80 Total Solids (pph)				
81 Total Flow (pph)		156499	16329	8620
82				
83 Total Flow (pps)		43	5	
84 Pressure (psia)		15	15	
85 Temperature (F)		90	90	

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6c Air Atmosphere Coal Dryer @ 1.25 lb/lb Coal	6d Heated Drying Air Drying Air Heater Crusher Mill	6e Classifier Air Classifier & Filter Coal Gas Burner @ 0.01% Solids	6f Dust Collector Exhaust Classifier Dust Collector Forced Draft Fan Intake @ 99% Removal Effic.	6g Dust Collector Exhaust Hopper Dust Collector Forced Draft Fan Intake	
0	0	0	0	0	0 11
0	0	0	0	0	0 12
7	922	922	7	7	0 13
96	425	425	96	96	1 14
0	0	0	0	0	0 15
0	0	0	0	0	0 16
0	0	0	0	0	0 17
0	0	0	0	0	0 18
11,336	11,336	11,336	11,336	84	19
198	198	198	198	1	20
0	0	0	0	0	0 21
0	0	0	0	0	0 22
0	0	0	0	0	0 23
0	0	0	0	0	0 24
0	3	3	0	0	0 25
0	0	0	0	0	0 26
3,472	3,233	3,233	3,472	26	27
0	0	0	0	0	0 28
0	0	0	0	0	0 29
0	0	0	0	0	0 30
0	0	0	0	0	0 31
0	0	0	0	0	0 32
15,110	16,117	16,217	16,217	112	33
					34
		1.69	0.017	6.43E-04	56
		0.11	0.001		58
		0.28	0.003	1.08E-04	59
		0.03	0.0003	1.16E-05	60
		0.02	0.0002	9.01E-06	61
					62
		0.05	0.0005	1.76E-05	63
					64
					65
					66
		0.07	0.001	2.81E-05	67
					68
		0.37	0.004	1.42E-04	69
		2.63	0.03	1.00E-03	70
15,110	16117	16220	16217	16117	71
					72
4.20	4	5	5	4	73
14.7	14.7	14.7	14.7	14.7	74
80	500	150	367	367	75

02	DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced)			Reference Coal - Fort Mart
03	Mass & Energy Balance	5 ft Dia Test Size	CRSS Predicted Output	*Us
04				
05	Stream No.		8	9
06	Identification		Coal/Limestone Fines	Compressed Air
07	From		Classifier Dust Collector	High Pressure Compressor
08	To		R Martin Coal Pile	Total
09	Gas	Mol Wt	lb/hr	lb/hr
10				
11	CO	28.010		0
12	H ₂	2.016		0
13	CO ₂	44.010		24
14	H ₂ O	18.016		321
15	CH ₄	16.042		0
16	C ₂ H ₆	30.068		0
17	H ₂ S	34.076		0
18	COS	60.070		0
19	N ₂	28.013		37924
20	Ar	39.948		664
21	HCl	36.461		0
22	HON	27.026		0
23	NH ₃	17.030		0
24	CS ₂	76.131		0
25	SO ₂	64.059		0
26	NO	30.006		0
27	O ₂	31.999		11615
28	NaCl	58.497		0
29	KCl	74.596		0
30	CaSO ₄	136.142		0
31	Ca(OH) ₂	74.095		0
32	CaO	56.079		0
33	Total Gas (lb/hr)			50548
34				
56				
57	C	12.011	1.6741	7
58	H	1.008	0.1072	36
59	O	16.000	0.2799	11918
60	N	14.007	0.0302	37924
61	S	32.060	0.0235	
62	CL ₂	35.500	0.0000	49884
63	H ₂ O	18.016	0.0457	
64	NaCl	58.497		
65	KCl	74.596		
66	CaSO ₄	136.142		
67	Ca	40.080		
68	CaO	56.079		
69	ASH, Inerts (pph)		0.3694	
70	Total Solids (pph)		2.5300	0
71	Total Flow (pph)		13	50548
72				
73	Total Flow (pps)		0.004	9
74	Pressure (psia)		15	600
75	Temperature (F)		80	200

n - Low Sulfur - 11/13/92 - MGAS Kinetics
 ng FW Data (High Steam - Low Blu) Case

Table 2.4

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9a				9b		9c	
Compressed Air@ High Pressure Compressor Pyrolyzer				Coal/Lm's in Convey Air High Pressure Compressor Pyrolyzer		Compressed Air High Pressure Compressor Pyrolyzer	
lb/hr	mol wgt	wt %	mol%	lb/hr			
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
15	0.01	0.06	0.03	3		12	
196	0.18	0.84	1.02	37		159	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
23186	21.65	75.03	77.28	4397		18739	
406	0.38	1.31	0.95	77		329	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
7101	6.63	22.98	20.72	1347		5754	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
0	0.00	0.00	0.00	0		0	
30904	28.86	100.00	100.00	5860		25043	
4				7608			
22				487			
7286				1272			
23186				137			
				107			
30498	Total			0			
				100			
				0			
				0			
				0			
				332			
				0			
				1679			
0				11721			
30904	29693			17581		25043	
8.58				5		7	
600				600		600	
150				200		200	

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2 | DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced) Table 2
3 | NEPA Support Document, Mass Balance *Using FW Data (High Steam - Low Blu) Case
4 |

5 Stream No.	9d				
6 Identification	Compressed Air@	0.83 A/C			
7 From	High Pressure Compressor				
8 To	Gasifier Grate				
9 Gas	lb/hr	lb-mol/hr	wt %	S/A	mol%
10					
11 CO	0	0.00	0.00		
12 H2	0	0.00	0.00		
13 CO2	5	0.01	0.05		
14 H2O	64	0.18	0.64		
15 CH4	0	0.00	0.00		
16 C2H6	0	0.00	0.00		
17 H2S	0	0.00	0.00		
18 COS	0	0.00	0.00		
19 N2	7527	21.65	75.03		
20 Ar	132	0.38	1.31		
21 HCl	0	0.00	0.00		
22 HCN	0	0.00	0.00		
23 NH3	0	0.00	0.00		
24 CS2	0	0.00	0.00		
25 SO2	0	0.00	0.00		
26 NO	0	0.00	0.00		
27 O2	2305	6.63	22.98		
28 NaCl	0	0.00	0.00		
29 KCl	0	0.00	0.00		
30 CaSO4	0	0.00	0.00		
31 Ca(OH)2	0	0.00	0.00		
32 Cl2	0	0.00	0.00		
33 Total Gas (lb/hr)	10033	28.66	100.00		1
34					
56					
57 C	1				
58 H	7				
59 O	2365				
60 N	7527				
61 S					
62 CaO	9901 Total				
63 H2O					
64 NaCl					
65 KCl					
66 CaSO4					
67 Ca					
68 CaS					
69 ASH, Inerts (pph)					
70 Total Solids (pph)	9728				
71 Total Flow (pph)	9728				
72					
73 Total Flow (pps)	2.70				
74 Pressure (psia)	600				
75 Temperature (F)	225				

1.5

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					2
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2	DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced)						
3	NEPA Support Document, Mass Balance			*Using FW Data (High Steam - Low Blu) Case			
4							
5	Stream No.		10	10a			
6	Identification		Feed to Pyrolyzer	Products of Pyrolysis - Gases			
7	From		Coal, Air, Steam	Pyrolyzer Section			N in coal to NH3 in gas
8	To		Pyrolyzer Inlet	Upper Area of Gasifier			90.00% Conversion
9	Gas		lb/hr	lb/hr	lb-mol/hr	wt %	mol%
10							
11	CO	28.010	0	4859	173.48	13.29	12.52
12	H2	2.016	0	264	130.74	0.72	9.43
13	CO2	44.010	15	5741	130.45	15.70	9.41
14	H2O	18.015	197	1460	81.02	3.99	5.85
15	CH4	16.042	0	256	15.96	0.70	1.15
16	C2H6	30.068	0	0	0.00	0.00	0.00
17	H2S	34.076	0	113	3.33	0.31	0.24
18	COs	60.070	0		0.00	0.00	0.00
19	N2	28.013	23186	23274	830.84	63.66	59.96
20	Ar	39.948	406	442	11.06	1.21	0.80
21	HCl	36.461	0		0.00	0.00	0.00
22	HCN	27.026	0		0.00	0.00	0.00
23	NH3	17.030	0	150	8.81	0.41	0.64
24	CS2	76.131	0		0.00	0.00	0.00
25	SO2	64.059	0		0.00	0.00	0.00
26	NO	30.006	0		0.00	0.00	0.00
27	O2	31.999	7101		0.00	0.00	0.00
28	NaCl	58.497	0		0.00	0.00	0.00
29	KCl	74.596	0		0.00	0.00	0.00
30	CaSO4	136.142	0		0.00	0.00	0.00
31	Ca(OH)2	74.095	0		0.00	0.00	0.00
32	Cl2	56.079	0		0.00	0.00	0.00
33	Total Gas (lb/hr)		30904	36715	1385.68	100.00	100.00
34							
56							
57	C	12.011	7612		3846	3842	-0.10%
58	H	1.008	509		520	525	0.79%
59	O	16.000	8558		8646	8711	0.75%
60	N	14.007	23323		23323	23398	0.32%
61	S	32.060	107		107	107	0.01%
62	CaO	35.500	30498				
63	H2O	18.016	100	Carbon Utilized			50.55%
64	NaCl						
65	KCl						
66	CaSO4						
67	Ca		332				
68	CaS						
69	ASH, Inerts (pph)		1679				
70	Total Solids (pph)		11721	36715			
71	Total Flow (pph)		42625	36715			
72							
73	Total Flow (pps)		11.84	10.20			
74	Pressure (psia)		600	600 # No Heat Loss, Reduce Air Flow to Control Te			
75	Temperature (F)		150	1652 temp(F), calc. adiab. temp(F)= 3052			

Table 2.6

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10b		10c				10d		
Products of Pyrolysis - Solids		Gases - Upper Portion of Gasifier				Solids - Upper portion of Gasifier		
Pyrolyzer Section		Pyrolyzer Section				Pyrolyzer Section		
Upper Area of Gasifier		Fixed Bed				Fixed Bed		
lb/hr	wt %	lb/hr	lb-mol/hr	wt %	mol%	lb/hr	wt %	
		4537	161.98	9.83	9.63			4
		137	68.06	0.30	4.05			5
		6955	158.02	15.06	9.40			6
		3225	179.00	6.98	10.64			7
		0	0.00	0.00	0.00			8
			0.00	0.00	0.00			9
		113	3.33	0.25	0.20			10
			0.00	0.00	0.00			11
		30485	1088.25	66.03	64.71			12
		568	14.22	1.23	0.85			13
			0.00	0.00	0.00			14
			0.00	0.00	0.00			15
		150	8.81	0.32	0.52			16
			0.00	0.00	0.00			17
			0.00	0.00	0.00			18
			0.00	0.00	0.00			19
			0.00	0.00	0.00			20
			0.00	0.00	0.00			21
			0.00	0.00	0.00			22
			0.00	0.00	0.00			23
			0.00	0.00	0.00			24
			0.00	0.00	0.00			25
			0.00	0.00	0.00			26
			0.00	0.00	0.00			27
			0.00	0.00	0.00			28
			0.00	0.00	0.00			29
			0.00	0.00	0.00			30
			0.00	0.00	0.00			31
			0.00	0.00	0.00			32
		46791	1681.66	100.00	100.00			33
								34
3766	63.73		3843	3843		3766	69.17	56
Carbon Remaining			531	531				57
49.50%			10977	10512				58
			30608	30608				59
			107	107				60
465								61
								62
								63
								64
								65
								66
								67
								68
1679	28.40					1679	30.83	69
5910	92.62	46791				5445	100.00	70
5910		46791				5445		71
								72
1.64		13.00				1.51		73
600		600				600		74
1652		2336		est. temp	2336	2336		75

DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced)

NEPA Support Document, Mass Balance *Using FW Data (High Steam - Low Blu) Case

4	5 Stream No.	6 Identification	7 From	8 To	9 Gas	Mol Wt	10	10e Gases Evolved through Gasification Down Through Fixed Char Bed Slowed Endothermic Reaction Point	11	12	13	14
								lb/hr	lb-mol/hr	wt %	mol%	
11	CO					28.010		9797	349.76	20.53	19	
12	H2					2.016		280	138.95	0.59	7	
13	CO2					44.010		4382	99.57	9.18	5	
14	H2O					18.015		1948	108.11	4.08	5	
15	CH4					16.042		0	0.00	0.00	0	
16	C2H6					30.068		0	0.00	0.00	0	
17	H2S					34.076		113	3.33	0.24	0	
18	COs					60.070		0	0.00	0.00	0	
19	N2					28.013		30485	1088.25	63.88	60	
20	Ar					39.948		568	14.22	1.19	0	
21	HCl					36.461		0	0.00	0.00	0	
22	HCN					27.026		0	0.00	0.00	0	
23	NH3					17.030		150	8.81	0.31	0	
24	CS2					76.131		0	0.00	0.00	0	
25	SO2					64.059		0	0.00	0.00	0	
26	NO					30.006		0	0.00	0.00	0	
27	O2					31.999		0	0.00	0.00	0	
28	NaCl					58.497		0	0.00	0.00	0	
29	KCl					74.596		0	0.00	0.00	0	
30	CaSO4					136.142		0	0.00	0.00	0	
31	Ca(OH)2					74.095		0	0.00	0.00	0	
32	CaO					56.079		0	0.00	0.00	0	
33	Total Gas (lb/hr)							47723	1810.99	100.00	100	
56												
57	C					12.011			5397	5397		
58	H					1.008			531	531		
59	O					16.000			10512	10512		
60	N					14.007			30608	30608		
61	S					32.060			107	107		
62	CL2					35.500						
63	H2O					18.016						
64	ZnFe2O4											
65	ZnS											
66	FeS											
67	Fe2O3											
68	ZnO											
69	ASH											
70	Total Solids											
71	Total Flow (pph)							48345				
72												
73	Total Flow (pps)							13.43				
74	Pressure (psia)							600				
75	Temperature (F)							1591				

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[illegible]

2 | DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced)

3 | NEPA Support Document, Mass Balance

*Using FW Data (High Steam - Low Blu) Case

Stream No.	Identification	From	To	Gas	10h			
					Mixture of Gases from Upper Bed and Lower Bed		86 scf/lb of c	
					Gasifier		Combustor	
					lb/hr	lb-mol/hr	wt %	mol
11	CO	28.010			13487	481.52	20.74	
12	H ₂	2.018			464	230.26	0.71	
13	CO ₂	44.010			6666	151.47	10.25	
14	H ₂ O	18.016			5428	301.31	8.35	
15	CH ₄	18.042			0	0.00	0.00	
16	C ₂ H ₆	30.068			0	0.00	0.00	
17	H ₂ S	34.076			113	3.33	0.17	
18	COS	60.070			0	0.00	0.00	
19	N ₂	28.013			38012	1356.96	58.46	
20	Ar	39.948			700	17.52	1.08	
21	HCl	38.461			0	0.00	0.00	
22	HCN	27.026			0	0.00	0.00	
23	NH ₃	17.030			150	8.81	0.23	
24	CS ₂	76.131			0	0.00	0.00	
25	SO ₂	64.059			0	0.00	0.00	
26	NO	30.006			0	0.00	0.00	
27	O ₂	31.999			0	0.00	0.00	
28	NaCl	58.497			0	0.00	0.00	
29	KCl	74.596			0	0.00	0.00	
30	CaSO ₄	136.142			0	0.00	0.00	
31	Ca(OH) ₂	74.095			0	0.00	0.00	
32	Cl ₂	56.079			0	0.00	0.00	
33	Total Gas (lb/hr)				65021	2551.16	100.00	
56								
57	C	12.011				7602	7602	
58	H	1.008				1105	1105	
59	O	16.000				17372	17372	
60	N	14.007				38136	38136	
61	S	32.060				107	107	
62	CaO	35.500						
63	H ₂ O	18.016			Sub-Totals	64321	64321	
64	NaCl							
65	KCl							
66	CaSO ₄							
67	Ca							
68	CaS							
69	ASH, Inerts (pph)				17			
70	Total Solids (pph)				17			
71	Total Flow (pph)				65333			
72								
73	Total Flow (pps)				18.15			
74	Pressure (psia)				600			
75	Temperature (F)				1568			

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2	DOE - GPIF - CRSS Coal Gasification Process						
3	Mass & Energy Balance		*Using FW Data (High Steam - Low Blu) Case				
4							
5	Stream No.		12a		12b		
6	Identification		Water Spray		Steam Injection		
7	From		Gasifier Outlet		Gasifier Outlet		
8	To		Combustor/HGCU		Combustor/HGCU		
9	Gas	Mol Wt	lb/hr	wt %	lb/hr	wt %	lb/hr
10							
11	CO	28.010					13487
12	H2	2.016					464
13	CO2	44.010					6666
14	H2O	18.016	2,900	100.00	0	100.00	8328
15	CH4	16.042					0
16	C2H6	30.068					0
17	H2S	34.076					113
18	COS	60.070					0
19	N2	28.013					38012
20	Ar	39.948					700
21	HCl	36.461					0
22	HCN	27.026					0
23	NH3	17.030					150
24	CS2	76.131					0
25	SO2	64.059					0
26	NO	30.006					0
27	O2	31.999					0
28	NaCl	58.497					0
29	KCl	74.596					0
30	CaSO4	136.142					0
31	Ca(OH)2	74.096					0
32	CaO	56.079					0
33	Total Gas (lb/hr)		2,900	100.00	0	100.00	67921
34							
56							
57	C	12.011					
58	H	1.008					
59	O	16.000					
60	N	14.007					
61	S	32.060					
62	Cl2	35.500					
63	H2O	18.016					
64	NaCl	58.497					
65	KCl	74.596					
66	CaSO4	136.142					
67	Ca	40.080					
68	CaO	56.079					
69	ASH, Inerts (pph)						
70	Total Solids (pph)						
71	Total Flow (pph)		2,900		0		68233
72							
73	Total Flow (pps)		0.81		0.00		18.95
74	Pressure (psia)		600		600		600
75	Temperature (F)		80		700		1350

Table 2.9

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12 Raw Gas Outlet Gasifier Outlet Combustor (Phase I)/HGU (Phase II)			13 = 13a & 13b Nitrogen Inerting Nitrogen Tanks PyGas™ Gasifier & Locks		14 Ash & Carbon Gasifier Ash Removal		Uncomb % of C 0.20%	14a Ash Lock Hopper Oxidation Reactor	
b-mol/hr	wt %	mol%	lb/hr		lb/hr	wt %		lb/hr	
481.52	19.86	17.75							2
230.26	0.68	8.49							3
151.47	9.81	5.58							4
462.30	12.26	17.05							5
0.00	0.00	0.00							6
0.00	0.00	0.00							7
3.33	0.17	0.12							8
0.00	0.00	0.00							9
1356.96	55.97	50.03							10
17.52	1.03	0.65							11
0.00	0.00	0.00							12
0.00	0.00	0.00							13
8.81	0.22	0.32							14
0.00	0.00	0.00							15
0.00	0.00	0.00							16
0.00	0.00	0.00							17
0.00	0.00	0.00							18
0.00	0.00	0.00							19
0.00	0.00	0.00							20
0.00	0.00	0.00							21
0.00	0.00	0.00							22
0.00	0.00	0.00							23
0.00	0.00	0.00							24
0.00	0.00	0.00							25
0.00	0.00	0.00							26
0.00	0.00	0.00							27
0.00	0.00	0.00							28
0.00	0.00	0.00							29
0.00	0.00	0.00							30
0.00	0.00	0.00							31
0.00	0.00	0.00							32
2712	100	100							33
									34
					15	0.88		15	56
									57
								89	58
					0	0.00			59
					0	0.00		60	60
									61
									62
									63
									64
									65
								1218	66
								222	67
									68
					1679	99.12		460	69
					1693	100.00		2064	70
					1693			2064	71
									72
					0.47			0.57	73
					15			14.7	74
					700			90	75

DOE - GPIF - CRSS Coal Gasification Process

Mass & Energy Balance

*Using FW Data (High Steam - Low Blu) Case

Stream No.	Identification	From	To	Gas	Mol Wt	15 Make-up Water Service Water Oxidation Reactor lb/hr	15a Overflow Oxidation Reactor Settling Tank lb/hr	15b Thickened Slurry Settling Tank Drum Filter lb/hr
11	CO				28.01			
12	H2				2.016			
13	CO2				44.01			
14	H2O				18.015			
15	CH4				16.042			
16	C2H6				30.068			
17	H2S				34.076			
18	CO2				60.07			
19	N2				28.013			
20	Ar				39.948			
21	HCl				36.461			
22	HCN				27.026			
23	NH3				17.03			
24	CS2				76.131			
25	SO2				64.059			
26	NO				30.006			
27	O2				31.999			
28	NaCl				58.497			
29	KCl				74.596			
30	CaSO4				136.1416			
31	Ca(OH)2				74.09474			
32	Cl2				35.5			
33	Total Gas (lb/hr)							
56								
57	C				12.0105			
58	H				1.008			
59	O				15.9995			
60	N				14.0065			
61	S				32.06			
62	CaO				56.0794			
63	H2O				18.0155	856	12535	
64	NaCl				58.497			
65	KCl				74.596			
66	CaSO4				136.1416		1827	
67	Ca				40.08			
68	CaS				72.14			
69	ASH, Inerts (pph)						690	
70	Total Solids (pph)					856	15353	
71	Total Flow (pph)					856	15353	
72								
73	Total Flow (pps)					0.24	4.26	
74	Pressure (psia)					14.7	14.7	
75	Temperature (F)					80	90	

Table 2.10

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15a	15c Overflow Settling Tank Oxidation Reactor lb/hr	15d Vent Oxidation Reactor HRSG Burner lb/hr	16 Air Oxidation Air Blower Oxidation Reactor lb/hr	17 Drum Filter Vent Vacuum Pump Atmosphere lb/hr	18 Gypsum & Ash Drum Filter R Martin Land Fill lb/hr	2
						3
						4
						5
						6
						7
						8
						9
						10
						11
		0.43	0.43	0.23		12
		446	5.64	9.41		13
						14
						15
						16
						17
		688.66	688.66	358.85		18
		12.06	12.06	6.28		19
						20
						21
						22
						23
						24
						25
		42.18	210.92	109.91		26
						27
						28
						29
						30
						31
		1189	918	484.68		32
						33
						34
						56
						57
						58
					89	59
						60
						61
						62
3851	8985				406	63
						64
						65
1846	183				1354	66
					222	67
						68
621	69				460	69
6117	9236	1189	918	485	2531	70
6117	9236	1189	918	485	2531	71
						72
2	2.57	0.330	0.25	0.135	0.70	73
14.7	14.7	14.7	15	14.7	14.7	74
90	90	90	90	90	90	75

2	DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced) Table 2.11					
3	*Using FW Data (High Steam - Low Blu) Case					
4						
5	Stream No.	19	19a	20	20a	20b
6	Identification	Condensate	Steam	Feedwater	Feedwater	Feedwater
7	From	R Martin	HRSG	Water Treatment	Water Treatment	Water Treatment
8	To	GPIF	R Martin	GPIF	HRSG	Start-up Bol
9	Gas	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
10	Mol Wt					
11	CO	28.010				
12	H2	2.016				
13	CO2	44.010				
14	H2O	18.015	14507			
15	CH4	16.042				
16	C2H6	30.068				
17	H2S	34.076				
18	CO3	60.070				
19	N2	28.013				
20	Ar	39.948				
21	HCl	36.461				
22	HCN	27.026				
23	NH3	17.030				
24	CS2	76.131				
25	SO2	64.059				
26	NO	30.006				
27	O2	31.999				
28	NaCl	58.497				
29	KCl	74.596				
30	CaSO4	136.142				
31	Ca(OH)2	74.095				
32	Cl2	35.500				
33	Total Gas (lb/hr)		14507			
34						
56						
57	C	12.011				
58	H	1.008				
59	O	16.000				
60	N	14.007				
61	S	32.060				
62	CaO	56.079				
63	H2O	18.016	84157	10000	10000	10
64	NaCl	58.497				
65	KCl	74.596				
66	CaSO4	136.142				
67	Ca	40.080				
68	CaS	72.140				
69	ASH, Inerts (pph)					
70	Total Solids (pph)					
71	Total Flow (pph)	84157	14507	10000	10000	10
72						
73	Total Flow (pps)	23	4	3	3	
74	Pressure (psia)	200	600	600	600	
75	Temperature (F)	382	700	80	80	

Q1	Q2	Q3	Q4	Q5	Q6	Q7
1	2	3	4	5	6	7
2	3	4	5	6	7	8
3	4	5	6	7	8	9
4	5	6	7	8	9	10
5	6	7	8	9	10	11
6	7	8	9	10	11	12
7	8	9	10	11	12	13
8	9	10	11	12	13	14
9	10	11	12	13	14	15
10	11	12	13	14	15	16
11	12	13	14	15	16	17
12	13	14	15	16	17	18
13	14	15	16	17	18	19
14	15	16	17	18	19	20
15	16	17	18	19	20	21
16	17	18	19	20	21	22
17	18	19	20	21	22	23
18	19	20	21	22	23	24
19	20	21	22	23	24	25
20	21	22	23	24	25	26
21	22	23	24	25	26	27
22	23	24	25	26	27	28
23	24	25	26	27	28	29
24	25	26	27	28	29	30
25	26	27	28	29	30	31
26	27	28	29	30	31	32
27	28	29	30	31	32	33
28	29	30	31	32	33	34
29	30	31	32	33	34	35
30	31	32	33	34	35	36
31	32	33	34	35	36	37
32	33	34	35	36	37	38
33	34	35	36	37	38	39
34	35	36	37	38	39	40
35	36	37	38	39	40	41
36	37	38	39	40	41	42
37	38	39	40	41	42	43
38	39	40	41	42	43	44
39	40	41	42	43	44	45
40	41	42	43	44	45	46
41	42	43	44	45	46	47
42	43	44	45	46	47	48
43	44	45	46	47	48	49
44	45	46	47	48	49	50
45	46	47	48	49	50	51
46	47	48	49	50	51	52
47	48	49	50	51	52	53
48	49	50	51	52	53	54
49	50	51	52	53	54	55
50	51	52	53	54	55	56
51	52	53	54	55	56	57
52	53	54	55	56	57	58
53	54	55	56	57	58	59
54	55	56	57	58	59	60
55	56	57	58	59	60	61
56	57	58	59	60	61	62
57	58	59	60	61	62	63
58	59	60	61	62	63	64
59	60	61	62	63	64	65
60	61	62	63	64	65	66
61	62	63	64	65	66	67
62	63	64	65	66	67	68
63	64	65	66	67	68	69
64	65	66	67	68	69	70
65	66	67	68	69	70	71
66	67	68	69	70	71	72
67	68	69	70	71	72	73
68	69	70	71	72	73	74
69	70	71	72	73	74	75
70	71	72	73	74	75	76
71	72	73	74	75	76	77
72	73	74	75	76	77	78
73	74	75	76	77	78	79
74	75	76	77	78	79	80

	QT	QU	QV	QW	QX	QY	QZ
Process	Table 2.12						3/10/93 16:43
1s	21						
indill	Trace Elements GPIF Flue Gas R. Martin Stack lb/hr	Trace Elements Combined Ash Fl. Martin Ash Landfill lb/hr	Trace Elements Combined Flue Gas R. Martin Stack lb/hr	Trace Elements Change Due To GPIF R. Martin Ash Landfill %	Trace Elements Change Due To GPIF R. Martin Stack %		
TO ARITHMETICALLY COMPUTE.							VALUES BASED ON RELEVANT PUBLICATIONS IN THE LITERATURE.
0260	0.000043	0.75378	0.00416	1.574	-0.905		
0900	0.001220	14.67923	0.25199	0.047	-1.452		
0400	0.00061	105.36880	0.37171	0.007	-1.795		
0270	0.000012	1.36272	0.00629	0.053	-1.742		
0220	0.00815	27.32627	3.00107	0.355	-1.662		
0062	0.0000080	0.29112	0.00187	0.212	-1.508		
0810	0.000204	9.24313	0.08808	0.030	-1.702		
0740	0.000020	3.78156	0.01336	0.028	-1.782		
0930	0.000114	9.90412	0.05709	0.102	-1.733		
0340	0.000237	6.76260	0.08164	0.053	-1.644		
0530	0.000176	26.66433	0.11884	0.148	-1.784		
0011	0.000901	0.01336	0.18361	6.871	-1.446		
0450	0.000037	2.03946	0.01867	0.283	-1.735		
080	0.000128	8.65259	0.05554	0.013	-1.703		
0335	0.000779	1.56882	0.34128	0.296	-1.705		
0730	0.000166	13.60699	0.08617	0.079	-1.740		
0273	0.0000050	1.30369	0.00461	0.168	-1.823		
0290	0.000010	1.98404	0.00697	0.037	-1.788		
1.73	0.01	235.31	4.69	0.009	-1.795		
526	0.437	92557	325				
531	0.45	92792.48	329.97	0.58	-1.795		
ss							
indill	Trace Elements GPIF Flue Gas R. Martin Stack lb/hr	Trace Elements Combined Ash Fl. Martin Ash Landfill lb/hr	Trace Elements Combined Flue Gas R. Martin Stack lb/hr	Trace Elements Change Due To GPIF R. Martin Ash Landfill %	Trace Elements Change Due To GPIF R. Martin Stack %		
0260	0.000043	0.75665	0.00418	1.96	-0.52		
0900	0.001220	14.73585	0.25297	0.43	-1.07		
0400	0.000510	105.77534	0.37317	0.39	-1.41		
0270	0.000012	1.36798	0.00631	0.44	-1.36		
0220	0.008150	27.43134	3.01285	0.74	-1.28		
0062	0.0000080	0.29224	0.00188	0.60	-1.12		
0810	0.000204	9.27878	0.08842	0.42	-1.32		
0740	0.000020	3.79615	0.01341	0.41	-1.40		
0930	0.000114	9.93430	0.05732	0.41	-1.35		
0340	0.000237	6.78868	0.08196	0.44	-1.26		
0530	0.000176	26.76707	0.11931	0.53	-1.40		
0011	0.000901	0.01341	0.18433	7.26	-1.06		
050	0.000037	2.04731	0.01874	0.67	-1.35		
080	0.000128	8.68597	0.05576	0.40	-1.32		
035	0.000779	1.57356	0.34262	0.60	-1.32		
030	0.000166	13.65945	0.08651	0.46	-1.35		
073	0.0000050	1.30871	0.00463	0.55	-1.44		
090	0.000010	1.99169	0.00700	0.42	-1.40		
073	0.01	236.20	4.71	1.23	-1.41		
26	0.437	93867	327				
81	0.45	94103.19	331.26	0.95	-1.41		

2 DOE - GPIF - CRSS Coal Gasification Process, Phase II, Hot Gas Cleanup Unit (HGCU)
3 NEPA Support Document, Mass Balance *Using FW Data (High Btu - Low Btu) Case

4	Stream No.		22		23		24	
5	Identification		Hot Raw Coal Gas		Hot Raw Coal Gas		Zinc Titanate (ZN4)	
6	From		PyGas™		PyGas™		(or Zinc Ferrite) Makeup	
7	To		HGCU Absorber		spec vol		HGCU	
8	Gas		lb/hr		scfm		lb/hr	
9								
10								
11	CO	28.010		13487		3036		
12	H2	2.016		464		1452		
13	CO2	44.010		6666		950		
14	H2O	18.016		8328		3720		
15	CH4	16.042		0		0		
16	C2H6	30.068		0		0		
17	H2S	34.076		113		21		
18	COS	60.070				0		
19	N2	28.013		38012		8517		
20	Ar	39.948		700		447		
21	HCl	36.461				0		
22	HON	27.026				0		
23	NH3	17.030		150		0		
24	CS2	76.131				0		
25	SO2	64.059				0		
26	NO	30.006				0		
27	O2	31.999				0		
28	NaCl	58.497				0		
29	KCl	74.596				0		
30	CaSO4	136.142				0		
31	Ca(OH)2	74.095				0		
32	Cl2	35.500				0		
33	Total Gas (lb/hr)			67921		18142		
34								
56								
57	C	12.011		7602				
58	H	1.008		1430				
59	O	16.000		19947				
60	N	14.007		38836				
61	S	32.060		107				
62	CaO	56.079	-----					
63	H2O	18.016		67922				
64	Zinc Titanate or Zinc Ferrite		-----				68	6
65	KCl	74.596						
66	CaSO4	136.142						
67	Ca	40.080						
68	CaS	72.140						
69	ASH, Inerts (pph)			311				
70	Total Solids (pph)			311			68	6
71	Total Flow (pph)			68233			68	6
72								
73	Total Flow (pps)			19			0.02	0.0
74	Pressure (psia)			600			14.7	14.7
75	Temperature (F)			1350			80	1350
76								

Table 2.13

3/10/93 17:19

25 Steam HRSG HGU lb/hr	26 Air Compressor Dryers HGU Regenerator lb/hr	27 @ SO ₂ vol = 1% Regeneration Gas Regenerator		28 Desulfurized Gas HGU Absorber		Desulfurized Gas HGU Absorber		mol%
		HRSG lb/hr	spec vol scfm	HRSG lb/hr	lb-mol/hr	spec vol scfm		
			0	13494	481.76	3037	17.76	
			0	464	230.26	1452	8.49	
	3	3	0	6666	151.47	950	5.58	
0	41	41	0.7	8328	462.30	3720	17.04	
			0		0.00	0	0.00	
			0		0.00	0	0.00	
			0	1	0.03	0	0.00	
			0		0.00	0	0.00	
	4865	4865	1090	38012	1356.96	8517	50.03	
	85	85	54	700	17.52	447	0.65	
			0		0.00	0	0.00	
			0		0.00	0	0.00	
			0	150	8.81	0	0.32	
			0		0.00	0	0.00	
		213	20		0.00	0	0.00	
			0		0.00	0	0.00	
	1490	1384	273	107	3.33	21	0.12	
			0		0.00	0	0.00	
			0		0.00	0	0.00	
			0		0.00	0	0.00	
			0		0.00	0	0.00	
0	6485	6591	1438	67923	2712	18144	100	32
0	1	1		7605		7602	-0.04%	
0	5	5		1423		1430	0.46%	
0	1614	1614		20058		19947	-0.55%	
0	4865	4865		38836		38836	0.00%	
0		107		1		0		
0	6485	6592		67923		67815	-0.16%	
0	6485	6591		67923				
0.00	1.80	1.83		18.87				
600	600	600		600				
700	200	1350		1350				

2	DOE - GPIF - CRSS Coal Gasification Process (Kinetically Balanced)					Table 2.1
3	NEPA Support Document, Mass Balance		*Using FW Data (High Steam - Low Blu) Case			
4						
5	Stream No.	1		Sorb/Coal	2	
6	Identification	Raw Coal		0.088	Limestone	
7	From	R. Martin Pile		GPIF Covered Pile		
8	To	GPIF Receiving Hopper		GPIF Receiving Hoppe		
9	Gas	Mol Wt	wt %	2.50 *Ca/S Mole Ratio		
10						
11	CO	28.010				
12	H2	2.016				
13	CO2	44.010				
14	H2O	18.015				
15	CH4	16.042				
16	C2H6	30.068	Proximate Analysis			
17	H2S	34.076				
18	COs	60.070	Vol Matter	28.92%		
19	N2	28.013	Fixed Carbon	54.86%		
20	Ar	39.948	Moisture	1.81%		
21	HCl	36.461	Ash	14.41%		
22	HCN	27.026				
23	NH3	17.030				
24	CS2	76.131				
25	SO2	64.059				
26	NO	30.006				
27	O2	31.999				
28	NaCl	58.497				
29	KCl	74.596				
30	CaSO4	136.142				
31	Ca(OH)2	74.095				
32	Cl2	35.500				
33	Total Gas (lb/hr)					
34						
56			Ultimate Analysis			
57	C	12.011	69.03%	8344	88%	
58	H	1.008	4.48%	542	Purity	
59	O	16.000	8.03%	971	443	
60	N	14.007	1.26%	152		
61	S	32.060	0.98%	118		
62	CaO	56.079	0.00%	0		
63	H2O	18.016	1.81%	219	1%	
64	NaCl	58.497			Moisture	
65	KCl	74.596				
66	CaSO4	136.142				
67	Ca	40.080			370	
68	CaS	72.140				
69	ASH, Inerts (pph)		14.41%	1742	124	
70	Total Solids (pph)			12088	1061	
71	Total Flow (pph)			12088	1061	
72						
73	Total Flow (pps)			3.36	0.29	
74	Pressure (psia)			14.7	14.7	
75	Temperature (F)			80	80	

Proposed Ties Between GPIF and Ft. Martin

CRS Sirrine Engineers, Inc.
Project 31604.00
Approved by: R.S. Sadowski
January 4, 1993

GPIF Air Compressors
21,000 Lb/Hr

Figure 6

permitted levels. However, the need for the Phase II hot gas cleanup system is potentially of much greater significance to future emission limitations either legislated or required for future fuel cell combined cycle application. To insure that the GPIF does not add to the current sulfur emission levels of the Fort Martin Station, it is proposed that only low sulfur coal will be gasified until such time that the GPIF can be shown to be capable of achieving no net sulfur emissions increase on high sulfur coal. This can only be demonstrated after startup and demonstration on low sulfur coal.

One (1) by approximately 5 ft diameter PyGas™ test sized gasifier is expected to generate sufficient coal gas to test the gasification process while firing the fuel gas (approximately 150-million Btu/hr coal feed rate) in a fired Heat Recovery Steam Generator (HRSG) (Phase 1).

The PyGas™ test gasifier will be designed to utilize approximately 12,000 lb/hr of coal at 600 psi operating pressure.

A zinc ferrite type (or zinc titanate) hot gas cleanup process is contemplated for high efficiency sulfur removal and sorbent regeneration under Phase 2, and a conventional sulfur recovery process may be planned for the production of this valuable by-product of sulfur capture. The initial plan, however, is to return the captured sulfur oxides back to the HRSG as sulfur oxides and hence to the Fort Martin Unit #2 breeching to the electrostatic precipitator. Therefore, secondary firing with coal gas will be carried out in the HRSG, and the resulting products of combustion will be injected directly into the inlet side of the existing Fort Martin Unit #2 electrostatic precipitators. In the event of boiler shutdown or failure during gasifier operation, the coal gas must be directed to an emergency flare.

During normal operations, to the extent practical, all process vents and reliefs shall be directed to the auxiliary steam boiler for combustion. If the auxiliary boiler trips, then vents shall be bypassed to the emergency flare.

9. Functional Descriptions of Test Facility - Phase 1

Conceptual Design of the Gasification Product Improvement Facility

Coal Receiving & Storage

Coal will be dumptruck delivered from the existing nearby Fort Martin low sulfur coal storage facility to a covered, live day bin. Provisions shall be made to collect all rainwater runoff, and pump it to the existing Fort Martin waste water treatment system. The required front end loader for loading from the utility coal pile as well as coal (also limestone and ash) trucks are expected to be subcontracted to a local trucking company familiar with current ash disposal requirements.

Coal Reclaim

Live coal pile management is expected to be by front loader. Reclaim is accomplished via a weigh belt feeder capable of 0 to 12,000 lbs /Hr coal feed rate directly onto a continuous conveyor belt. The conveyor belt deposits coal continuously into a crusher/dryer (drying heat to come from a tubular type air heater located downstream of the fired auxiliary steam generator), thence to an inlet coal (and limestone) lock hopper of sufficient capacity for coal and limestone

inventory discharge from the weigh belt feeder to the continuous conveyor belt discharge. Therefore all load change and accurate metering is accomplished by the weigh belt feeder. Provisions shall be made to collect all rainwater runoff, and pump it to the existing Fort Martin waste water treatment system. The feeding and conveying systems shall be properly ventilated, and the vented air shall be filtered before being released to the atmosphere.

Limestone Receiving & Storage

Limestone is received by dumptruck (by others) from an existing nearby rail unloading or quarry facility and dumped directly into a covered, live day bin. Provisions shall be made to collect all rainwater runoff, and pump it to the existing Fort Martin waste water treatment system. The feeding and conveying systems shall be properly ventilated, and the vented air shall be filtered before being released to the atmosphere.

The current plan is to operate the pyrolyzer tube in the slug-flow region at approximately 3.5 fps because Charlie Lowell (ref: DOE DE-AC21-78MC10484) was successful at that point. This is effectively the same velocity as what Foster Wheeler calls "jetting". Therefore, the same 1/8 inch minus dolomite and 16 x 200 mesh limestone size gradation which Foster Wheeler (ref: DOE DE-AC21-86MC21023) was successful with will initially be utilized at the GPIF.

Since milling is complicated by the differences in grindability or "work index" between limestone and coal (limestone is usually harder), we plan to receive pre-sized limestone or dolomite at 16 x 200 mesh and 1/8 inch minus respectively.

While this will lead to a smaller size fraction entering the gasifier, the tortuous path and co-current flow regime serve to assure calcination without unreacted limestone carryover. In turn, there will be less likelihood of "blinding" calcium sulfide crystals with an outside layer of larger gypsum crystals because of the greater surface to volume ratio of the smaller sized limestone. This is really something which we need to test to verify anyway, so these comments merely reflect our logic for a starting point. These comments have been added to the report.

Limestone Reclaim

Limestone pile management is expected to be by front loader. Reclaim is accomplished via a weigh belt feeder capable of 0 to 4,000 lbs /Hr limestone feed rate directly onto the coal conveyor belt thereby assuring homogeneity between coal and limestone with a minimum of solids attrition. The conveyor belt deposits the mixture of coal and limestone continuously into a crusher/dryer, thence to an inlet coal (and limestone) lock hopper of sufficient capacity for coal and limestone inventory discharge from the weigh belt feeder to the continuous conveyor belt discharge. Therefore all load change and accurate metering is accomplished by the weigh belt feeder.

Ash Handling & Storage

Ash sources include mainly the gasifier bottom ash along with a minor source from the gasifier outlet cyclone. Gasifier bottom ash will be pneumatically

conveyed into a 100 ton ash silo. Gasifier outlet cyclone solids will also be pneumatically conveyed into the same ash silo. Since the PyGas™ process provides an oxidation zone immediately above the rotating grate, it is expected that retained sulfur in the ash will be predominantly in the fully sulfated form.

In the event the ash contains unsulfated forms of sulfur, it will be first fed to a submerged combustion reactor to complete the sulfation reaction prior to disposal in the permitted Fort Martin existing coal ash landfill. While the quantity of GPIF ash to be added to the existing ash landfill is extremely small relative to current fill rates, it is likely to contain some unreacted alkali which should serve to provide some neutralization benefit in the ash pile.

Ash Conditioning & Disposal

The ash is removed from the ash silo conical bottom via a water cooled ash conditioning screw into an ash disposal truck. During periods of limestone utilization, care must be exercised to minimize the use of any water spray for dust control to avoid heat increase by chemical reaction with unreacted but calcined lime. An ash removal truck fitted with bag filter vents is preferred followed by Water conditioning or the current method used at the permitted Fort Martin solid waste land fill site may be considered to minimize dusting. The PyGas™ coal gasification process is designed to produce sulfated ash product which is expected to be free of sulfides. However, provisions shall be made to oxidize all ash generated in the process in a submerged combustion reactor. The exhaust from this reactor shall be vented to the auxiliary steam boiler for additional combustion. The treated ash is then dewatered through mechanical filtration equipment, temporarily stored in the ash silo, and transported by truck to the existing ash pond area of the Fort Martin power plant. Fort Martin has an air permeable dust screen at their landfill site. While some air can pass through it, it does provide a good buffer on windy days resulting in less particulate becoming air-borne. We anticipate approximately 15% free moisture per Page 92 Figure 6. The anticipated properties are moist but dry handling granular solids, and conventional ash hauling trucks will be able to handle it.

The ash silo is sized for 100 tons. This is about four days of ash at full load and should accommodate weekends and holidays. We do plan to normally have daily ash hauls.

Air Compressor

A four-stage centrifugal compressor will be used in conjunction with (2) reciprocating compressors to boost ambient air to 650 psia for injection into the gasifier. The centrifugal air compressor will incorporate two intercoolers and one aftercooler to control inlet air temperatures to stages 2 and 3 and the reciprocating compressor, respectively. The total air compressor package will consume 1.66 MWe. Cooling water needed for the intercoolers will be minimized by allowing larger temperature rises in the cooling water, if practical. Although this will increase power consumption and decrease compressor efficiency, it may allow the intercoolers to be used as economizers to preheat the necessary water for the cycle while at the same time decreasing water consumption from the host utility.

In addition to providing compressed air for the gasifier, the air compression system will be designed to allow instrument air bleed after the aftercooler which is placed in between the centrifugal and reciprocating air compressors. The instrument air will be extracted at 205 psia, 100°F and the pressure reduced to the instrument requirements.

Proprietary CRS Serrine Engineers, Inc. PyGas™ Gasifier

The gasifier will be a shop fabricated water cooled vessel with three flanges, capable of operation at up to 600 psig. It will include a pressure lock upstream of its pneumatic crushed coal conveying pipe, and an ash pressure lock at the bottom of the gasifier vessel. A rotating grate similar to any conventional fixed-bed gasifier will be furnished complete with its motor drive assembly. Metered air, steam, and water spray nozzles will be furnished at three critical points within the gasifier vessel. The pressure locking valves will operate such that a continuous pressure seal is maintained constantly. A suitable purge and vent system and media will be incorporated into the design to avert reverse flow of hot coal gas into the coal feed system. An emergency (only) vent and flare stack will also be incorporated to automatically operate in the event of GPIF overpressure or a rare unrelated Ft Martin Unit 2 master fuel trip since the GPIF flue gas flow to it should be discontinued during such an upset condition.

Hot Coal Gas Piping

The test gasifier includes four (4) inch insulated and lagged stainless steel hot gas piping.

The hot low Btu gas produced by the gasifier shall be discharged to the primary gas cyclone via four (4) inch stainless steel piping insulated with calcium silicate insulation of seven (7) inch thickness and lagged.

Hot Cyclone

The gasifier outlet cyclone is an insulated stainless steel device intended to capture solids which carryover from the gasifier with the coal gas. It is anticipated that since it has performed well previously, the current GE cyclone will be scaled up to the size required for the gas throughput requirement (approximately a 12 to 1 scale up). The cyclone's captured fines stream discharge by gravity and requires a pressure locking chamber to partially depressurize the fines stream for pneumatic conveyance to the ash silo, separate sampling, or for reinjection back to the gasifier. The hot cyclone is approximately 13 ft tall by 2 ft diameter

The gasifier gas outlet cyclone may alternatively be a carbon steel device with 12" thick refractory liner, intended to separate solids carryover from the gasifier in the hot gas by centrifugal force. It is expected that the primary cyclone shall separate up to 600 lbs per hour of solids (char). As the gas stream and the cyclone shall operate at approximately 600 psig and 1120°F, the fines from the cyclone collection chamber shall be discharged via lock hopper and auto valves operated in sequence.

These locks shall initially be pressurized with inert gas up to the cyclone's operating pressure to prevent coal gas escape when the upper valve is opened to

admit solids. Before the fines are discharged via the pneumatic conveying system to ash storage silo, the lock hopper may be depressurized to near atmospheric pressure, or the inert media at pressure may be used to convey fines.

Vent Pipe, Rupture Disc, Detonation Arrestor and Emergency Flare

A rupture disc, detonation flame arrester and vent stack with emergency flare are anticipated to be required in the gas line between the gasifier and primary gas cyclone for emergency pressure relief. These devices are specifically designed to relieve and arrest the high velocity and pressure flame fronts that may accidentally develop in the gas piping from gasifier, and to carry any deflagration front from the gasifier, away from personnel and out the top of the building for combustion prior to release to the atmosphere.

The Protectoseal model F25006, 6" bi-directional detonation flame arrester in 316 SS housing is included.

Vortex Type Burner

A single vortex type coal gas burner (Coen or equal) shall be utilized to add sufficient air to the coal gas to completely combust the gaseous fuel product of the gasifier. The coal gas burner nozzle is rated at 154-million Btu/hr coal gas firing rate (including sensible heat in the coal gas). The coal gas firing rate is consistent with an excess air of approximately 10% at MCR which is normal for gas fired burners. While past experience has shown the ability to completely combust hot coal gas without support fuel requirements above 50% gasifier load, provisions shall be made to provide for flame stabilization support using light oil fuel using an NFPA Class I ignitor flame. Therefore, under any operating load, whenever the main flame scanner indicates the need for support flame, the ignitor shall be capable of being automatically placed in flame support service.

It is anticipated that the coal gas will be utilized to produce gasification process steam as well as for auxiliary steam generator duty for return to Fort Martin Station. This will allow the GPIF facility to operate at full capacity while the existing utility boiler operates at anywhere from half to full load. The intent is to render the effect of GPIF operation on the existing utility station to the insignificant level.

Water Spray Injection

It is anticipated that water mist and steam will be sprayed into the hot raw gas from the GPIF such that the coal gas pipe temperature to the fired heat recovery steam generator (HRSG), and eventually in Phase II to the hot gas cleanup system does not exceed approximately 1100 -1400 degrees F. In this manner the coal gas piping is protected from excessive temperature at the 600 psig operating pressure. The heat of evaporation minimizes water requirements.

Gasifier Water Jacket Steam Generator

The GPIF gasifier test unit includes steam generation heat recovery intended to provide a significant portion of the necessary steam for gasifier steam injection

requirements. In this manner, the test facility may be steam self sufficient after startup. This then may allow the packaged boiler steam supply source to be required only during test startup. It has been determined that sufficient heat is available from the compressor intercooler, gasifier water jacket, and gasifier carbonizer tube cooling to generate the entire gasifier steam demand.

Water/Steam Loop

A pump forced "once through" water cooled intercool loop is contemplated to control compressor temperatures up to 600 psia air compression. The same water cooling intercooler loop may then be circuited to the gasifier water jacket, possibly the gasifier carbonizer tube, and subsequently back into the gasifier grate air blast. The alternative is a circuit to the existing Ft Martin cooling tower.

Feed Water Pump

The feed water pump must be sized to provide sufficient water for steam generation for gasifier grate air blast injection. Cooling water for air compressor intercooler will necessitate pump operating pressure significantly greater than the ultimate 600 psia needed for the gasifier. A 750 psia operating pressure is neither inconceivable nor particularly difficult to obtain from a number of suppliers. The cost estimate includes a 50 gpm feedwater pump for cooling and coal gas sprays, plus a 25 gpm feedwater pump booster for steam generation. If acceptable to the host utility, a feedwater bleed from the feedwater heater loop may be utilized in lieu of the above pumps.

An alternative under consideration is to receive feed water from Ft Martin using a booster pump, and make intermediate steam (600 psia/ 700°F) in the HRSG for use in the gasification system with all excess steam going back to the utility's cold reheat system. This alternative provides Ft Martin with more efficient use of steam generated in the GPIF system.

Water/Steam Considerations

The proprietary PyGas™ test gasifier requires up to 10,080 lb/hr of steam for the gasification of caking coal. There are several heat sinks within the cycle that will be used to generate the needed saturated steam at gasifier pressure. The statement of work indicates that the 650 psia steam is required at 640 F. This is well above the saturation temperature of 495 F associated with the above pressure. It is contemplated that the heat sinks within the process provide enough heat to generate saturated steam at the gasifier pressure. The last heat sink would be the gasifier water jacket and carbonizer tube. Once the saturated steam leaves the gasifier water jacket, the steam is mixed with the compressed air. Since the air leaving the compressor is approximately 700 F, the steam mixed with the air will stay well above the saturation point and remain in a dry state.

To generate 10,080 lb/hr of 650 psia saturated steam, 11.85 million Btu/hr of heat must be absorbed by incoming water at 60 F. The heat sinks within the system are the intercoolers and aftercoolers in the air compression system, the gasifier water-cooled carbonizer tube, and the water/steam jacket on the gasifier. The water/steam jacket absorbs 8.47 million Btu/hr and the gasifier carbonizer tube

absorbs 1.97 million Btu/hr for a total of 10.44 million Btu/hr of the needed 11.85 million Btu/hr. The remaining 1.41 million Btu/hr of heat can be absorbed from the air compressor intercoolers.

The information above indicates that the needed steam can be generated from the heat sinks within the process thus integrating the process as desired.

Process Water Distribution System

The process water shall be distributed from the main process water line main near Monongahela Power's Unit No. 2 as shown on Exhibit 2 of the site tour of June 18, 1991.

The total process water consumption at the pressure 70 psig is estimated as:

Table 3
Process Water Consumption

1.	GPIF feed water	25 gpm
2.	Coal gas cooling	5 gpm
3.	Ash conditioning	1 gpm
4.	Cooling Water Consumption	<u>500 gpm</u>
	Total	531 gpm

A 2 inch main is included to supply this quantity of process water for the facility.

Cooling Water Distribution

The cooling water distribution to the gasifier jacket, coal gas cooling and carbonizer tube cooling is estimated at 25 gpm. Cooling water from the GPIF will be returned to the existing Fort Martin Unit #2 cooling tower. There will not be a separate GPIF cooling tower.

Packaged Boiler, Fired Heat Recovery Steam Generator (HRSG), & Induced Draft Fan

A small light oil fired packaged boiler is contemplated for space heating and gasification process steam raising during startup. In addition, a coal gas fired HRSG and tubular type coal dryer air heater followed by an induced draft fan shall provide the heat recovery system for returning the Btu's from the gasification of coal to the host utility. If necessary, the startup and space heating packaged boiler flue gas may be vented into the induced draft fan along with the coal gas fired auxiliary steam generator flue gas for removal back to the existing Fort Martin Unit #2 stack.

Gasifier Integrated Steam Source

The test gasifier will require up to 0.84 lb of steam per lb of coal gasified. With the test gasifier consuming 12,000 lb of coal per hour, this equates to 10,080 lb/hr of steam. A small packaged boiler will be used for startup. Since, the air discharged from the compressor is at 700°F, saturated steam at gasifier pressure produced in the water/steam jacket can be mixed with the air to insure that the steam will remain dry. This prevents condensation in the pipes. Some 11.8 MMBtu/hr of heat must be absorbed to generate 10,080 lb/hr of saturated steam at 650 psia. Therefore, 8.5 MMBtu/hr is transmitted to the steam jacket of the gasifier. The remaining 3.4 MMBtu/hr of heat needed to make the saturated steam will be absorbed by the water through the heat sinks in the cycle. This heat will be absorbed by the water through the use of carbonizer tube cooling and intercoolers/aftercoolers of the compressor as economizers.

Boiler Chemical Treatment

All water makeup to the auxiliary boiler and reactor cooling jacket shall be softened and injected with environmentally acceptable oxygen scavengers and corrosion inhibitor chemicals.

Desulfurization

Provisions have been made for limestone feed to the proprietary PyGas™ coal gasifier. Based upon the results of other pyrolyzer tube testing, approximately 20% to 95% sulfur retention may be possible within the gasifier itself. This retained sulfur will be removed from the gasifier and disposed of in the Fort Martin Generating Station permitted coal ash landfill along with the gasifier bottom ash. It is expected that this solid waste product will contain some unsulfated alkali such that some beneficial neutralization of the currently slightly acidic coal ash contained within the landfill may occur. The expected range of calcium to sulfur mole ratios anticipated for testing is 1.0 to 3.0. Depending on sulfur content in the coal, this results in up to approximately a half ton of limestone per hour.

Potable Water

A one inch potable water line and reservoir tank is included from the utility interface point to the GPIF for lavatory and shower consumption.

Test Facility Horsepower Requirements

The following table serves to identify the anticipated motor horsepower requirements of the conceptualized test facility.

Table 4
Test Facility Motor Horsepower Consumption

The following is a list of motor and horsepowers associated with the test facility.

<i>Equipment Description</i>	<i>Horsepower</i>	<i>K W</i>
Gasifier		
Rotary Coal Metering Drives (2)	10.0	7.45
Grate Drive	15.0	11.18
Air Compressor		
Centrifugal Compressor	1750.0	1305.0
Reciprocating Compressor (2)	700.0	522.2
Coal Receiving/Storage/Reclaim		
Pile Runoff Collection Sump Pump	1.0	0.74
Gravimetric Feeder Drive	3.0	2.24
Transfer Conveyor Drive	10.0	7.45
Vent Fan Drive(Pit Ventilation)	7.5	5.59
Sample Cutter Drive	1.0	0.74
Coal Crusher/Dryer Drive	20.0	14.90
Limestone Receiving/Storage/Reclaim		
Gravimetric Feeder Drive	3.0	2.24
Sample Cutter Drive	1.0	0.74
Coal Gas Combustion/Heat Recovery		
Forced Draft Fan Motor	125	93
Feedwater Pumps	10.0	7.5
Induced Draft Fan Motor	400	298
Wet Oxidation System		
Vacuum Filter Pump Motor	N/A	N/A
Transfer Pumps (2)	N/A	N/A
Oxidation Air Blower Motor	N/A	N/A
Ash Handling System		
Ash Blower	<u>50.0</u>	<u>37.29</u>
Totals:	2,857	2,131

Process Building

The building shell erected shall be : 30'W X 100'L X 50'H

The LRF envelope frame with 0.5:12 slope and BR-II roof panels has a clearspan double slope profile with tapered sidewall columns. It offers almost total flexibility in sizes within the limits of the LRF envelope. The wall panels shall have 2" insulation in each. Two (2) 3' X 7" personnel doors, one (1) 10'

X 10' overhead door, one (1) 25' X 17'-6" removable wall panel, gutters and downspouts over entrance area only, exhaust fan (75,000 CF/hr air exchange), intake louvers are included in the building design.

The building foundation and 6" concrete slab, with 4' X 4' X 6' sump and three (3) 4" floor drains to the storm runoff collection pit.

One sump pump, capacity 30 gpm, 52 HTDH, 2 HP

Steel stairs outside to 12' high elevation, with steel treads, landings and handrails per code.

For the heat protection in the winter to maintain 50°F ambient temperature at 0° exterior temperature, the steam-fired or electric unit heaters are included using existing 600 psi steam or electricity from Ft Martin Station.

Control room inside process building area 12' X 12', with 3' X 7' personnel door with half glass.

On the top of control room, second floor testing room 12' X 12' area, one 3' X 7' personnel door with half glass, entrance from the inter platforms. Heat and air conditioning are included, with 2-1/2" concrete floor over steel form deck.

A lavatory facility, to include separate male & female showers, two toilet stalls (each for handicapped persons), two wash basins (one for handicapped persons), complete with standard fixtures will be provided. A pumping and storage tank for waste disposal by portable tank truck will also be furnished.

A furnished combination meeting and break room complete with dry erase marker board, sink and microwave oven, and with coffeemaking, snack and soda machine provisions will be provided. Furniture will consist of two 4 ft x 8 ft folding type tables and twelve (12) straight back chairs.

All process runoff shall be collected in a sump and pumped to the existing Fort Martin Generating Station waste water treatment system.

Ash and Other Process Waste Particulate Handling Storage And Disposal

Ash handling from gasifier bottom and process fines from the outlet of the hot cyclone shall be pneumatically conveyed periodically on a timed basis into a 100 ton ash storage silo, dimensions 14' dia X 28'H.

It is expected that the total solids collection from all above mentioning source shall be in the range of 4007 lbs per hour. The ash shall be discharged periodically from the bottom of gasifier to bottom ash lock hopper by way of airlocks operating in sequence. This cycle proceeds automatically on a timed sequence before accumulated fines shall be discharged to the pneumatic system. The lock hoppers shall be depressurized to an atmospheric pressure. Similar discharge lock hoppers shall be employed after the gas cleaning cyclone.

The ash and other waste solids (spent sorbent) shall be unloaded in the disposal truck by telescopic spout when limestone is fed to the gasifier, or by water cooled ash conditioner. (No limestone utilization). The filter-separator bag

shall be periodically cleaned by pressure air. The sequence shall be set by timer. Care must be exercised with ash conditioning water admixing whenever unreacted lime may be present, as heat of reaction and skin burns have been reported in industrial applications using lime. The ash silo shall be vented to the atmosphere by way of a bag filter or electrostatic precipitator.

10. Control and Instrumentation System Description

General

The test gasifier facility will be equipped with a state-of-the-art control and instrumentation system designed in accordance with the existing engineering practice for this type and size of equipment, with the scope sufficient to ensure a high level of facility's availability and reliability. Taking into account the experimental character of this facility, we have added a certain degree of redundancy, where exact process characteristics were unclear or required special attention to the process.

Process control and monitoring functions will be performed in a central control room (CCR) utilizing a microprocessor-based distributed control system (DCS) along with several dedicated control subsystems.

Conceptual design of the proposed system is illustrated in the system block diagram (Fig.1). From the control point of view, the overall plant equipment will be divided into several functional groups (FG), some of them will be equipped with their own, dedicated (possibly PLC-based) vendor supplied control systems, others will be controlled directly by DCS from CCR. Control systems of individual FG's will provide control interface and necessary inputs to DCS for centralized data acquisition, monitoring and reporting. These dedicated control systems may be based on PLC or DCS technology. Main requirements to their suppliers should be compatibility with the host DCS (i.e. the ability to communicate via a common data highway) and uniformity of their hardware basis (e.g. use of the same make of the PLCs).

The following FG's are expected to be controlled by their dedicated specialized control systems and/or PLC's via remote I/O racks:

- Coal/Limestone Loading System;
- Steam Generation - Coal Gas Flare, Boiler, Water Treatment;
- Existing Boiler Burner Interlock System;
- Compressed Air and Instrument Air Systems;
- Continuous Emission Monitoring (CEM) System;
- Ash Handling System;
- Balance of Plant Systems;

The following FG's are expected to be controlled directly by the DCS:

- Coal Gasifier with Primary Cyclone;
- Hot Gas Clean-up with Secondary Cyclone and Sulfur Recovery System;

Standards

The C&I system shall conform to the applicable industry standards, such as:

- National Fire Protection Association (NFPA)
- National Electric Code (NEC)
- National Electrical Manufacturers Association (NEMA)
- Instrument Society of America (ISA)
- Institute of Electrical and Electronics Engineers (IEEE)
- American National Standards Institute (ANSI)

Controls Equipment Scope of Supply

Control Room Equipment

We anticipate that the following operator interface equipment will be located in the CCR:

Table 5
Control Room Equipment

Equipment	Phase I	Phase II	Phase III
Operator Stations (CRT with keyboard)	3	4	5
Printers 2	3	3	
Plant Paging & Telephone System	1	1	1
Fire Protection System 1	1	1	
Main Control Room Panel	1	1	1
Sequence of Event Recorder	1	1	1
Emission Monitoring (CEM) and Reporting System	1	1	1
Logging Station w/printer	1	1	1
Video Copier	1	1	1

The following will be included with the DCS and located next to the CCR:

Engineering Station w/keyboard	1	1	1
Historical Data Storage	1	1	1
Printers	1	1	1

Control Systems and Equipment

The following FG control systems will be required and implemented for the two phases of the project outlined as follows:

Table 6
Control Systems & Equipment

Functional Group		
	Phase I	Phase II
Coal/Limestone Loading	Yes	Yes
Coal Gasifier	Yes	Yes
HGCU/Sulfur Recovery	No	Yes
Steam Generation - Flare/Boiler	Yes	Yes
Existing Boiler Burner Interlock System	Yes	Yes
Cont. Emission Monitoring (CEM)	Yes	Yes
Ash Handling	Yes	Yes
Compressed Air	Yes	Yes
Instrument Air	Yes	Yes

Control of Individual Functional Groups

Coal/Limestone Loading System

Coal and Limestone Loading System which includes coal and pebble limestone bunkers, gravimetric feeders, a common belt conveyor c/w the corresponding drives will be operated and controlled by a PLC-based local control system via remote I/O rack. A configured operator interface screen will be supplied for a window into the operation. The DCS will monitor and act as a data acquisition system via a data interface link between the DCS and PLC data highways.

Coal Gasifier System

The overall coal gasifier system, including the gasifier itself, coal feeding, air and steam supplies to the gasifier and coal gas system with the primary cyclone and (possibly) flare, will be controlled from the DCS via a dedicated redundant processor.

In order to monitor and control the position and intensity of the gasification zone in the coal gasifier, we are proposing to install 3 infrared (IR) monitors (scanners) on the sides of the gasifier. Each of these instruments will measure two parameters: intensity and frequency of the IR radiation, which, as we expect, will characterize the intensity and position of the zone of max heat generation. These parameter measurements will allow the operators, during the initial testing and commissioning period, to establish patterns of normal operation and to recognize patterns of abnormal situations. By applying methods of pattern recognition, IR monitors in combination with temperature measurements and gas analyzers will allow development of methods of positioning of the gasification zone and of optimizing the overall gasification process.

The gasifier system will also include a multipoint gas analyzer system to continuously monitor concentration of H₂S and other gaseous components at

the gasifier, primary cyclone outputs and within the process area. The gas analyzers will be located in the common chemical analysis room.

Our preliminary evaluation of the system control requirements indicates that the processor should be capable to support (approximately) the following number of I/O's:

Analog Inputs (TC's, RTD's, 4-20mA):	100
Analog Outputs:	25
Digital (on/off) Inputs:	75
Digital (relay) Outputs:	50

This system is based on the above I/O count and vendor quotations for control systems of a similar size and configuration.

Hot Gas Clean-up and Sulphur Recovery Systems

Control requirements for these systems include a substantial number of control functions, mostly sequential logic operations. These systems will be controlled directly by DCS via a dedicated redundant processor.

The HGCU will be served by the multipoint gas analyzer system to continuously monitor concentration of H₂S and other gaseous components in the hot coal gas upstream and downstream of the absorber and also will monitor oxygen in the regenerator system.

The latest GE RDC report of June 1980 and 50% contingency for the sulphur recovery system, we estimate that the system should be capable to support the following number of I/Os:

Analog Inputs (T/Cs and RTDs)	75
Analog Inputs (4-20 mA)	75
Analog Outputs	40
Digital (on-off) Inputs	120
Digital (relay) Outputs	100

Our estimate is based on this I/O count and a number of vendor quotations for similar size control systems.

This gas analyzer will be common for the gasifier and will be incorporated into one common gas monitoring system.

Steam Generation System

The Gasifier Steam Generation System will be operated and controlled by a PLC-based local control system via remote I/O rack. The system will execute all necessary water treatment, feedwater, steam temperature and combustion control functions required to meet the load demand and to maintain boiler parameters.

Coal Gas Combustion

The coal gas burners are expected to be equipped with a vendor supplied (possibly PLC-based) burner management system (BMS) containing complete package of instruments, valves, flame scanners, etc., to comply with the NFPA recommendations for coal-fired burners. The BMS will be connected to the DCS via hardwired connections and will be controlled from the CRT operator stations. Interlocks and permissives consistent with the safety shutdown philosophy of the existing Fort Martin Station utility boiler's burner management system will be provided. A remote indication of coal gas combustion and steam generation status will be provided and located in the existing Fort Martin Station utility control room.

Continuous Emission Monitoring System (CEM)

Emission monitoring equipment shall include stack analyzers to continuously monitor the flue gas exhaust for NO_x, SO₂, O₂, CO, H₂S and Opacity. The analyzers will be housed in a special environmentally controlled analyzer shelter adjacent to the exhaust duct of the auxiliary boiler. The analyzer housing will be shared with the bulk of the analyzer equipment which has to provide thorough monitoring of numerous gas components and solid particulates in the gasifier exhaust, primary and secondary cyclone outlets and HGCU outlet. The equipment will monitor facility compliance for all applicable Federal and State emission requirements. The system will be monitored by the DCS for alarms and critical measurements.

A stand alone personal computer located in the control room and software dedicated to the emission monitoring system will be included with the system. The equipment vendor will provide system certification, start-up assistance, installation supervision, personnel training and maintenance program.

Ash Handling System

Bottom Ash Removal, Handling and Storage System will be controlled with a PLC-based local control system via remote I/O. System design, scope of supply, functions and interface with the DCS will be similar to the Coal/Limestone Loading System.

Compressed Air and Instrument Air Systems (From Process Air Compressors)

These systems which include centrifugal and displacement type compressors, filters, dryers, and pressure regulators will be controlled by a PLC-based local control system via remote I/O racks.

DCS Capabilities and Controls

The DCS will include dynamic controllers, I/O racks, communication devices, and operator stations. The operator interface to the system will be through color

CRT's and operator keyboards which will be preprogrammed for easy access to color graphic displays and specialized operator functions.

The DCS will provide soft A/M stations for remote control of the various field devices and control loops. This control will be accomplished via the operator's CRT console and keyboard. The logic control functions, such as motor control and discrete monitoring, will be accomplished in the DCS using key selection and dynamic displays on the operator console. The configuration of function codes and control strategies will reside in the non-volatile memory and will be maintained in the event of a power failure.

The control schemes will be hardware and software configured with consideration for redundancy as applicable. In the event of any single failure of power supply, processor / controller or highway / communication link / data multiplexers, it will alert the operator while continuing to keep the process under uninterrupted automatic control from the CRT.

If the primary control processor should fail, a secondary processor (operating in the "hot stand-by" mode) will assume control responsibility with bumpless transfer. In the event of a failure of both processors, the system will be configured such that analog and digital outputs will go to pre-determined fail safe positions.

Communication to the individual dedicated PLC-based control systems will be accomplished via one common data interface link between the DCS and PLC data highways. A Performance Assessment package will be configured in the DCS. This software application will gather information for each system and will provide real time displays to the operator.

Power supplies will be redundant, so that in case of a power supply failure, a back-up power supply will assume responsibility. The Operator interface will provide a user friendly environment for control and data acquisition functions. This interface will provide access to plant wide operations allowing the operator to monitor and take corrective action as required. The displays will provide dynamic information by updating information and status displayed to the operator.

An Engineering workstation will allow personnel to configure operator consoles and control hardware. The software package will enable the engineer to design, configure, monitor, trend, tune, modify and document process activities. Graphic symbols and function codes will be used to build the process logic control drawings on the CRT screen. The Engineering workstation will be used during start-up and de-bugging stage of commissioning. It will also be used as a tool to maintain, troubleshoot, operate and re-configure the system if required once the plant is operating.

The DCS will be field maintainable and configurable by the owners personnel after appropriate training.

11. Electrical System Assessment

General Requirements

Load Profile - New Gasification Plant

4160 V. Load	2.85 MVA.
Total Load	3.4 MVA.

Project Concept

The Project concept is to supply existing Fort Martin Generating Station with steam from the proposed gasification plant. This plant is to be a stand alone satellite facility to be located in the vicinity of the generating station. All utilities are to be provided to the plant's battery limits. The 13.8 kV utilization voltage will require that the utility company furnish and install the required feeder to the plant's electrical system primary.

Codes and Standards

Except where noted, all electrical systems shall be designed, fabricated and installed in accordance with the latest edition of the National Electrical Code, and applicable ANSI, ICEA, NEMA, NESC, IEEE Standards as defined in the RFP (exceptions taken will be defined). Components that are UL listed and labeled shall be provided if required by local authorities.

Electrical Equipment

Selection and design of all electrical components and systems shall be in accordance with the applicable codes and standards. Reliability of operation shall be the primary consideration in the facility design. The Preliminary single line diagram will serve as a typical basis of supply (CRSS Drawing SK-E-001).

The electrical equipment shall include the following, located in the facility building:

Table 7

MEDIUM VOLTAGE SWITCH GEAR HV-1
LOW VOLTAGE SWITCHGEAR LVSWG-1
1750 HP STARTER WYE DELTA
2 (400HP) COMPRESSOR WYE DELTA
1200A NON-SEGREGATED BUS
MCC-001-GPIF
STATION BATTERY AND CHARGERS
"UPS" UNINTERRUPTABLE POWER SUPPLY

15 kV Pole Line (by utility company)

A 15 kV pole line feeder with parallel overhead ACSR conductors will interconnect the GPIF with the existing facility's 13.8 kV switchgear. This feeder line will be used to cold start the GPIF.

Plant's Primary Transformer

The plant's primary transformer "T1" will be 5 MVA, outdoor, oil filled, 13.8 kV delta to 4.16 kV resistance-grounded wye, standard impedance, equipped with special winding and cooling fans to permit temporary overloading and allow for future growth.

BUS DUCT.

The bus ducts shall be 5 kV, 1200 A, 3-phase, 3-wire plus ground, non-segregated phase type, rated to accommodate maximum design operating voltage. The rated momentary current will be based on the maximum three-phase fault current to which the bus can be subjected.

Coal Gasification Electric Power System (parasitic loads)

The electrical power system will perform the following functions:

Provide a reliable source of electrical power for plant auxiliaries during all operating conditions.

Provide rapid isolation of any faulted equipment without unnecessary loss of supply to other equipment.

Provide satisfactory motor starting and bus voltage regulation.

Medium Voltage Distribution Switchgear HVSWG-1
(4.16 KV, Vacuum Type, 350 MVA).

The circuit breaker and metering portions of the medium voltage switchgear will be a non-drawout, metal-clad, dead front, with each breaker cubicle isolated from the adjacent cubicle by a metal barrier. The interrupting ratings will be selected in accordance with ANSI Standard C37.010 making full allowances for asymmetrical symmetrical current ratios. Incoming breaker and internal bus continuous current ratings will be chosen to be greater than the maximum expected loading.

Medium Voltage Motor Controllers:

Motor controllers portion of the medium voltage switchgear will be of the draw-out full-voltage across-the-line or reduced vacuum type (as indicated on the single line diagram), rated a minimum of 400 MVA, double-stacked wherever possible.

The controller and the bus will be adequately rated for the voltage class, the continuous current and the available short circuit level.

The protective fuses will be ANSI Class "R" for motor starting duty, and class "E" for transformer feeder duty. Single-phase protection will be provided to open contactors whenever any fuse blows.

Overload, under-voltage, single-phasing and ground fault protection will be provided.

Control voltage will be 120 V AC.

Each controller will have an ammeter and an ammeter switch.

All motors shall have motor circuit protection.

The switchgear lineup will include provisions for future bus extension on one end.

Switchgear rooms will be mechanically cooled and pressurized with filtered air to prevent the entrance of dust and dirt. Switchgear rooms will have at least two exits to assure safe personnel egress.

Secondary Unit Substations.

The 480 volt systems will be 4-wire, 3-phase, wye connected, and solidly grounded at the transformer neutral.

Transformer "T2" shall be an indoor dry-type, cast-coil, standard impedance, rated 1000 kVA.

For ease of maintenance, the 480 volt switchgear will be located indoors in pressurized switchgear rooms or other clean areas. Cast-coil, dry type transformers will be used indoors.

Transformer cooling fans will be provided to allow for future load growth and permit temporary overloading. The unit substations will be physically arranged to allow future switchgear additions, and to allow for transformer removal and replacement.

Main circuit breakers will be fully-rated, manually-operated withdrawable, air-break, stored energy spring operated, dead-front type, complete with solid-state overcurrent and ground fault trip devices.

Bus shall be fully rated to supply a continuous load of 1600 A.

Loads supplied directly from unit substations will include motor control centers, and other 480 volt loads larger than 100 amperes.

Motor Control Centers and AC Distribution Panels.

MCC's will have NEMA Type 1A enclosures with gaskets on doors and filler plates, or NEMA Type 12 in Water Treatment Area. Locations will be chosen with care to avoid damp, dirty, or hot areas and to allow adequate front and rear access.

Motor control centers will utilize standard modules factory assembled in suitable shipping lengths.

Motor control centers will be rated 65,000 A.S.C. and have NEMA Class I, Type B wiring rated 600 volts for 480 volt service. The upper limit of motor size supplied from MCC starters will be 200 hp where application is continuous duty with infrequent starting. Larger motors may be controlled by MCC starters where the application involves intermittent duty. Dual mounted molded case circuit breaker feeder units will also be provided in MCC's to supply 480 volt unit-related loads that do not require remote control.

Bus shall be fully rated to supply a continuous load as shown on the drawings and specifications.

Each fully rated combination starter unit will be complete with a molded case circuit breaker having adjustable magnetic trips only, magnetic contactor, three bimetallic overloads, auxiliary contacts, control power transformer, and control wiring terminal block. Control power transformers will be adequately sized to power the motor starter as well as the auxiliary control devices. Starter controls will be 120 volt AC with a coil seal-in contact.

The breakers will have 65,000 A interrupting capacity adequate for the available short circuit current.

All motor starters will be of the same manufacturer to ensure interchangeability of parts and to minimize stocking of spare parts. In addition, circuit breaker distribution panels will be provided at selected locations, as required, to serve small loads.

A minimum of 20% fully equipped space shall be provided in the motor control center for future additions.

DC Battery Powered Systems (breaker control).

125 VDC battery system with an energy storage capacity of four (4) hour minimum will include a lead-calcium, solid state rectifier-battery chargers, and main DC distribution panels.

The battery capacities will be adequate to supply all associated loads for the required sequence, duration, and combinations that occur when each breaker unit must be operated with no other power sources available.

The battery nominal voltage, float voltage and end of discharge voltage will allow operation over a voltage range acceptable to standard NEMA equipment with only occasional need for recharging.

The battery chargers will be sized to supply those DC loads that exist continuously during normal unit operation while simultaneously recharging a fully discharged battery. The maximum battery recharge period will be 12 hours. Chargers must be capable of operation without the battery.

A circuit breaker DC distribution panel will be provided adjacent to the batteries to minimize the length and maximize the security of the battery feeder cables. The circuit breakers will have thermal-magnetic overload trips, except for circuits feeding emergency auxiliary motors, which will have magnetic trips only.

DC battery powered emergency lighting system shall be furnished similar to the above in all respects.

Grounding System.

In general, grounding system will be in accordance with the National Electrical Code and IEEE recommendations.

Instrument Grounding System.

A separate insulated grounding system will be provided for the computer and other noise sensitive electronic equipment. This will be a radial system, without loops and will be connected to the plant ground grid at one point only.

Instrument cable shields will be grounded at the load side only, leaving the sensor end ungrounded and insulated with the exception of thermocouples which are to be grounded at the instrument end.

Lightning Protection.

The lightning protection system will be designed in accordance with the National Fire Protection Association Lightning Protection Code (NFPA 78) Class I or Class II systems, UL96A, the National Electrical Code, IEEE Standards and the Lightning Protection Institute - Installation Code (LPI-175).

Electrical Heat Tracing.

Freeze protection and process heating systems will be provided for outdoor pipes, pumps, vessels and instrument sensing lines requiring process heating or freeze protection. The freeze protection system will automatically operate whenever the ambient falls below 40°F and will provide sufficient heat to prevent water freezing when the ambient temperature falls to 5°F less than the lowest ambient temperature recorded at the site. Control and monitoring systems for freeze protection will be centralized.

Lighting Systems.

Plant lighting will consist of normal lighting and self contained DC operated emergency lights.

Normal lighting will provide illumination during normal operating conditions.

Facility indoor lighting distribution will be three-phase, four-wire. A 480/277 volt system will be used. Facility outdoor lighting distribution will be 480 volt, three-phase, three-wire with phase-to-phase connected loads.

Indoor lighting circuits will be distributed through three-phase, four-wire lighting panels, which will be located centered to and near their respective loads to minimize voltage drops.

Distribution will be designed so that failure of any single lighting panel will not totally black out any floor or single large area.

Lighting equipment selection will be based on the requirements of specific areas. Incandescent, fluorescent, and high pressure sodium sources with appropriate luminaries will be used depending on the application and the needs of each location. High pressure sodium lighting will be used for outdoor installations.

Generally, the illumination levels for facility areas will be those recommended by the Illuminating Engineering Society.

Lighting circuits will be switched at their distribution panels. Rooms and small buildings will have light switches at each doorway. Outdoor lighting will be photoelectrically controlled with provisions for manual override.

Loop road lighting will be in accordance with recommendations of the National Illuminating Engineers Society. These fixtures shall be suspended from building structural walls or members.

Emergency AC and lighting system will be provided for purposes of personnel egress and continuation of critical activities during emergency conditions.

Design illumination levels for egress lighting will be those required by applicable Federal, state, or local fire codes.

Communication Systems.

Telephones will be provided in the control room, in the offices and electrical switchgear room.

A facility paging and two-party communication system, complete with amplifying equipment, handset stations and speakers will be provided.

UPS System.

UPS System shall be 30 KVA with two 200 A, 3 ph., 4W outputs plus isolated ground for process controls and system architecture power supplies, with 15 minute ride-through and lead-acid battery racks as required.

Emergency Process Equipment.

The compressed air, auxiliary boiler and gasifier jacket cooling water feed systems shall be capable of automatic switchover to the auxiliary DC power

source in the event of AC power source failure for equipment protection against overheating.

Life Safety System (fire alarms).

The zone panel shall be stand alone and report to a central command station located in the Engineer's Office. Total number of zones shall be at least 8 active with four spares.

Fire Protection System.

As separate electric source from Fort Martin Generating Station shall be utilized to power a dedicated fire pump serving the GPIF area in the event of fire.

12. Functional Descriptions - Phase 2

Conceptual Design for Coal Gasifier Test Facility

Hot Gas Cleanup Unit & Sulfur Recovery

This area will be added under Phase II of the Coal Gasifier Test Facility.

Fluid Bed Absorber

The fluid bed absorber follows the ground rules suggested by METC to furnish a two stage bed. Given the reaction kinetics for the sulfidation of zinc ferrite, we feel that a single bed might be adequate to get the desired H₂S removal. We assume a 2-stage bed is desirable for alternative research studies, and perhaps to produce ultra high sulfur capture, a landable goal.

Sorbent Regenerator

We have also used a riser tube sorbent regenerator as suggested by METC. If that arrangement is insufficient, we have allowed some space to install a moderately sized regenerator (fluid bed reactor) to obtain more residence time.

The revised arrangement could require the regenerator to be located above the absorber to permit gravity flow of regenerated sorbent into the absorber bed. That would raise the profile of the HGCU above the building roof thereby adding to the cost.

We have placed an airfin cooler to reduce the recycle gas to about 250-300°F as the recycle blower suction to allow standard materials (CS) in the blower.

Generally we are following the regenerator cooling cycle used by GE on their Schenectady pilot plant. It is believed that the system offers METC a flexible means to test various diluent circulating regimes to optimize the sulfur recovery feed gas.

Sulfur Recovery Unit

There are a variety of ways to convert the sulfur values in the off-gas to salable products.

The recovery of sulfur as sulfuric acid or liquid SO_2 are available as tested commercial processes so pilot plant study of such processes would be redundant.

The alternative of converting to elemental sulfur is supported by proven commercial processes such as the Allied/Davy Powergas SO_2 Reduction Process.

Sodium/alumina catalysts (RTI bench scale work)

The tail gas from sulfur recovery should have the capability to be recycled to the process to eliminate final treatment to meet air emission standards.

Disposal of the recovered sulfur may present a problem. Because the sulfur is produced on an intermittent basis according to the pilot plant schedule, it may be difficult to find a user who would accept it. Also, at this point we are not certain of the quality of sulfur produced.

Those factors indicate that disposal to a solid waste dump appears to be a likely method of disposal. Solid sulfur is relatively insoluble, but it is combustible giving off hazardous products of combustion. Therefore, it may not be acceptable in landfills. The disposal of the sulfur will have to be investigated when a specific site is selected during the detailed design phase.

Liquid or solid sulfur produced from the test facility is expected to be either sold or properly disposed of in a disposal facility permitted for this type of material.

As an alternate, regenerated sulfur dioxide may be piped back to the gasifier or auxiliary packaged steam generator for ultimate ducting back into the breeching of Fort Martin Unit #2 upstream of the electrostatic precipitators.

HGCU Description of Operation

Coal Gas Cycle:

The purpose of the HGCU is to remove the H₂S and sulfur compounds to a suitable level (<10 PPMV) from the coal gas stream. This unit also supplies the SO₂ rich feed gas to the direct sulfur recovery unit (DSRU).

The HGCU receives coal gas from the fines cyclone located in the gasifier area. The gas (which includes tars) is fed into the bottom of the HGCU absorber. The feed gas is at 600 psia and 1100°F.

The sorbent reagent is zinc ferrite with a binding agent to make a fluidizable grade catalyst. The zinc ferrite absorbs the sulfur bearing materials in the coal gas by converting the zinc and iron oxide components to zinc and iron sulfide. The sulfidation reaction is exothermic which raises the gas temperature to about 1200°F.

The coal gas passes through the perforated plate in the bottom of the absorber vessel. The gas fluidized sorbent bed allows intimate gas and sorbent contact.

The fluidizing coal gas then passes through a second perforated plate to a second fluidized sorbent bed. The final bed removes the last traces of sulfur bearing materials in the gas to a point less than 10 ppmv.

The cleaned coal gas passes out top of the absorber vessel through the internal cyclone which removes the larger particles from the gas and returns them to the upper bed through the cyclone dip leg.

The gas then passes through the sorbent fines cyclone to remove the sorbent fines from the coal gas before leaving the HGCU for delivery to the flare. The sorbent fines are removed to a tote bin through the cyclone lock hopper. The fines tote bin is either returned to the sorbent manufacturer or its contents are wasted to landfill depending upon sorbent economics.

Sorbent Cycle

The sorbent treats the coal gas in two fluidizer beds in the HGCU Absorber. In this process, the zinc ferrite is converted to zinc and iron sulfide. This action is known as "sulfidation".

The sulfidation reactions are as follows:

It is necessary to continuously remove the sulfidated sorbent from the fluid beds and reactivate it to zinc and iron oxides. This process is known as "regeneration".

The sorbent is withdrawn from the lower bed by gravity into the spent sorbent receiver through a pipe. The inlet of the pipe is located near the top of the lower bed to catch the overflow of the bed. The rate of flow is controlled by a slide gate or other type of valve.

The sorbent in the spent sorbent receiver is in turn fluidized by the recycle gas stream entering the bottom of the spent sorbent receiver. Air is fed into the fluidized stream to provide oxygen to oxidize the sorbent according to the following reactions:

The zinc sulfate reaction tends to occur at temperatures below 1200°F. Therefore, the regeneration temperature should be between 1250 and 1500°F.

The gas velocity in the riser tube is sufficient to transfer the sorbent up the tube to discharge into the regenerated sorbent cyclone. The cyclone drops out the sorbent into the body of the cyclone. The regeneration gas bearing the SO₂ gas leaves the top of the cyclone.

The regenerated sorbent is then fed by gravity into the upper fluid bed of the HGCU absorber. The flow rate of sorbent is controlled by a slide gate or other type of valve. The flow rate in the sorbent regeneration loop is controlled to prevent the break through of H₂S in the coal gas discharge. Break through would be any level above 10 ppmv of H₂S in the clean gas stream.

The sorbent passes from the upper bed to the lower bed through an internal standpipe to complete the sorbent cycle.

As the sorbent circulates, it wears and generates fines which are removed from the sorbent cycle. These losses are made up by feeding fresh sorbent through the fresh sorbent lock hopper. Fresh sorbent is received in tote bins from the sorbent manufacturer. Fresh sorbent batches are transferred through the fresh sorbent feeder and a dense phase pneumatic transfer system to the fresh sorbent lock hopper.

The fresh sorbent and fines lock hoppers must be vented and purged through the plant vent system to remove any coal gas in the vessels. This action is necessary from a safety and pollution control standpoint.

Regeneration Gas Cycle

The carrier gas for the regeneration reaction in the riser tube is handled in the regeneration gas loop. The purpose of this system is to provide diluent gas for diluting the oxygen fed into the riser tube (regenerator). Dilution and distribution of the oxygen feed is necessary to prevent overheating of the sorbent. The sorbent breaks down when heated over 1500°F.

After the recirculation gas leaves the top of the regenerated sorbent cyclone, it passes through a fines removal cyclone to remove entrained sorbent fines. The fines are removed through a lock hopper to a fines tote bin for disposal.

The gas then passes through a porous metal or ceramic medium filter to remove any fine dust that passes through the fines cyclone. This piece of equipment was added to ensure a clean gas stream to avoid fouling the downstream shell and tube heat exchangers. This may be an optional piece of equipment for the pilot plant depending upon the dusting characteristics of the new fluid bed sorbents being developed.

Because the sorbent regeneration reaction was exothermic, it is necessary to remove the heat of reactions from the system. It is also necessary to cool the recirculating gas to ca. 300°F at the recirculation blower inlet to avoid overheating and the requirement of exotic materials. The recirculating gas heat exchanger accomplishes the cooling by reheating the cool recirculating gas before it is fed to the regenerator. Cold gas feed is likely to thermally shock the hot sorbent.

The SO₂ rich offgas is removed from the recirculating gas stream at either side of the recirc gas heat exchanger. This allows the offgas stream to be taken off at either 400°F or 1100°F as desired. The SO₂ rich offgas is bled off the system through a flow meter and flow control valve to feed the sulfur recovery system or to atmosphere through the dry lime quench system to suit pilot plant operating plans.

The still hot recirc gas then passes through the air preheater to heat up the regeneration system air supply. The regeneration air is supplied from the gasifier compressed air system.

It may also be desirable to dry the regeneration air supply to keep moisture out of the recirc gas system. Moisture in the air could combine with the SO₂ gas in the system to form H₂SO₄ which, in turn could cause corrosion in the equipment.

The recirc gas then passes through an airfin cooling coil to trim out any residual heat to reduce the gas temperature to 300°F. The cooled recirc gas enters the recirculation blower which increases the gas pressure back to 600 psia to pump it around the system. The blower serves to overcome the system pressure drops such as the riser tube, cyclones, filter, heat exchangers, etc., required by the system.

The blower discharges through the shell side of the recirculating gas heat exchanger into the bottom of the spent sorbent receiver to complete the cycle.

The regeneration air supply is distributed to the air inlets on the regenerator riser tube to burn off the sulfur. The air flow is controlled by a temperature control system to prevent overheating in the riser tube.

A electrically powered start-up heater is provided at the discharge of the blower to heat up the system by circulating hot nitrogen. This would be done for a cold system start-up.

13. Project Environmental Aspects

The basic premise of the test facility is to operate it in such a way that it does not increase criteria pollutants over what would normally be emitted from the Fort Martin Station if the GPIF were not operating.

The test gasifier will potentially prove to be an air pollution control system for SO₂, NO_x, particulate and CO₂ mitigation, followed by a hot cyclone for additional particulate removal. An internal PyGas™ gasifier limestone based hot gas cleanup system to remove sulfur will be tested. Emissions are expected to be maintained well within limits of the new Clean Air Act for both 1995 and the year 2000 requirements with this potential second generation IGCC system which the project sponsor considers will likely become "Best Available Control Technology" (BACT).

14. Emission Reduction of NO_x

NO_x reduction during testing is anticipated to be achieved via a two pronged approach:

1. It has been shown that ammonia generation from fixed-bed gasifiers can be reduced by operation at low moisture (steam injection) levels in the gasifier where the coal's fuel bound nitrogen is released. The PyGas™ coal gasification process provides for coal devolatilization within the pyrolyzer section of the gasifier which is logically where fuel bound nitrogen will be released. The significant modelling effort using both the METC-MGAS and the KRW kinetic rate limiting mathematical expressions produced excellent results when less steam injection is introduced into the pyrolyzer or the top gas region of the PyGas™ gasifier. This is very significant in that it can be logically concluded that the PyGas™ gasifier can be controlled to produce the least amounts of ammonia when compared with other gasifiers by admitting less steam into the reaction where devolatilization and fuel nitrogen is released.
2. Acurex Corporation (DE-AC21-86MC23275) demonstrated 95% to 98% ammonia destruction through the use of staged combustion of low Btu coal gas. They concluded that ammonia is cracked in the first rich-burning stage, and higher pressure accelerates kinetics which favor more rapid ammonia destruction. They also concluded that fuel nitrogen can be controlled effectively.

It is the intention of this project to test rich/lean combustion of the low Btu coal gas produced from the PyGas™ gasifier, which we expect will demonstrate effective control of NO_x generation from the minimized ammonia produced from the PyGas™ gasifier.

Relative to current Fort Martin Unit #2 NO_x emissions, the GPIF will generate considerably less NO_x per unit of heat input because of the longer flame development and lower peak flame temperatures associated with low Btu/cu ft coal gas combustion. It is reasonable to expect at least a 25% NO_x reduction, however, since the firing rate is only approximately 1.5% of the Fort Martin Generating Station firing rate, an overall insignificant NO_x reduction is expected.

15. Greenhouse Gases and Air Toxics

There will be a slight theoretical, but likely unmeasurable increase in carbon dioxide and air toxic emissions during GPIF operations. This is due to minor anticipated GPIF thermal losses and heat losses through the insulation of the steam piping between the GPIF and Fort Martin Generating Station. The increase is expected to be on the order of 0.07%.

Although no direct reductions in carbon dioxide and air toxic emissions are anticipated from the GPIF during testing, successful testing will lead to coal fired power generating systems which will directly result in the reduction of greenhouse gases and air toxics.

Socioeconomically, eventual retrofitting any existing pulverized coal fired furnaces with coal gas burners, and repowering with the PyGas™ coal gasification process utilizes most of an existing coal fired power plant, and increases its output by 15% while reducing the coal input by 13%. Therefore, all emissions are proportionally reduced. The following calculated expected effluent quantities were produced for a CCT IV 300 MWe Fig. 2A Ref. Plt.:

Table 8
Effect of Repowering on Effluents

Effluent (Ref. Plt.)	Reference Plant lb/MMBtu	PyGas™ Gasifier R/R Plant lb/MMBtu
117.6 tons coal/hr 12,360 BTU/lb		
SO ₂	3.8	0.01
NO _x	1.2	0.03
CO ₂	200	174
Particulates	.1	.03
SO ₃	0.050	0.003
H ₂ S	unk	13% less
HCl	0.080	0.013
	tons/ton coal	tons/ton coal
Spent Sorbent	-	0.39
Coal Ash	0.16	0.16
Wastewater Suspended Solids	unk	13% less
Sulfur Byproducts	unk	0.05 liquid SO ₂
Water Consumption	unk	13% less

Future fully implemented coal gas burner retrofits to the existing furnaces with the GPIF PyGas™ gasifier in a combined repowering cycle are expected to reduce CO₂ (greenhouse gases) by 13% compared to the 300 MW Reference Plant. This is because the cycle heat rate is 8,281 BTU/kw vs. 9,493 BTU/kw for the Reference Plant. Construction of the GPIF and its subsequent test program are essential to meeting these future reduction potentials of full sized plants.

16. Production and Handling of Other Effluents

It has been reported by PSI Technology Company (DE-AC21-89MC26291) that aluminosilicates which occur naturally in coal ash are capable of tying up previously volatilized alkali species upon their condensation, a phenomenon which occurs within the PyGas™ coal gasifier during the endothermic char gasification reactions.

In like manner, it is likely that other volatilized trace metals can be effectively controlled within the PyGas™ coal gasification vessel, such that they become part of and are removed with the bottom ash from the PyGas™ gasifier. Since the final gasification process prior to the removal of gasifier ash is that of combustion of remaining ash carbon, the ash is subjected to an

oxidizing atmosphere where such metals can become chemically stabilized and rendered non-leaching.

Coal ash is an unavoidable by-product of any coal conversion process, and must be discharged as a solid from the gasification system. Other solid wastes include desulfurization system by-products, and a small amount of sorbent material from zinc ferrite pellet decomposition from decrepitation. The quantities of such materials can only be determined by testing which is the objective of the GPIF project.

Liquid wastes include storm water runoff, submerged combustor blowdown and boiler water blowdown. These streams will be collected in a waste water holding tank and returned to the existing Fort Martin Station waste water system.

Acids and bases from the waste water holding tank will be neutralized before discharge back to the Fort Martin wastewater treatment system. Sanitary waste streams will be collected, removed from the premises by permitted sanitation trucks and treated in the conventional manner for such systems.

A distinct advantage of hot gas cleanup systems is that they do not produce process condensates which could contain dissolved and suspended hydrocarbons, ammonia, and other contributors to chemical oxygen demand (COD), and biological oxygen demand (BOD), and toxicity, because the coal gas is maintained well above the dew point of condensible species.

17. EHSS Compliance

Emissions regulations with which the GPIF will comply are:

- Existing Source Performance Standards (ESPS) as defined for coal fired utility boilers under the new Clean Air Act.
- National Pollution Discharge Elimination Standards (NPDES), state and local regulations for cooling water discharge.
- RCRA, state and local solid waste disposal regulations.

It is expected that testing will confirm that the GPIF will comply with the criteria emission limits of the Clean Air Act, and the ultimate result of this R&D facility will be the development of combined cycle systems which will achieve stack emissions levels well below those required by the new Clean Air Act. The new Clean Air Act required levels are interpreted to be as follows:

SO₂: 50% SO₂ reduction by 1995, and 1.2 lb/million Btu by the year 2000 for high and medium sulfur coal

NO_x: 0.6 lb/million Btu

Particulates: 0.03 lb/million Btu

Compliance with OSHA regulations for personnel protection will be ensured during construction and initial subsystem test operation of the GPIF.

18. Plan For EHSS Risks and Impacts

Due to the flammable and toxic nature of coal gas, monitoring and alarm systems as well as a flare dump stack are planned. Carbon monoxide and hydrogen sulfide monitors are expected to be placed at several strategic locations within the coal gasification and hot gas cleanup systems. Self contained breathing apparatus will also be located throughout the facilities.

Continuous in situ emission monitoring is expected in the flue gas ductwork and at the exit of the hot gas cleanup system to assure emission levels are within compliance levels. Provisions for alarming and fail safe plant operation are anticipated in the event of a major system failure resulting in a master fuel trip. As with all fixed-bed coal gasifiers, it is anticipated that the PyGas™ gasifier will be capable of being "banked" by subtending coal, steam, and air flow.

Monitoring:

A summary of monitoring categories is as follows:

- Process Monitoring
- Stack
- Ambient Air
- Solid Waste
- Waste Water
- Industrial Hygiene

Detailed monitoring plans will be prepared during the permitting process.

Toxic elements are present in trace levels in coal ash. Emission of these trace elements to the atmosphere, although not currently regulated, are being given considerable scrutiny by regulators and technologists. Following is a listing of average values of trace element in 101 coal analyzed by the Illinois State Geological Survey. The potential concentrations and tonnages of these trace elements released to the atmosphere are:

Table 9
Trace Elements Present in Coal Ash

Element	Amount in Coal, ppm	Amount Emitted, Tons/Year
Lead	34.8	24,673
Arsenic	14.02	9,940
Cadmium	2.52	1,787
Selenium	2.08	1,475
Beryllium	1.3	922
Mercury	0.2	142

The emissions of trace metals may be controlled to an as yet undeterminable extent within the PyGas™ gasifier vessel by virtue of its endothermic cooling zones where coal ash is exposed and available to chemically tie up those trace metals which condense at the operating temperature of the gasifier (1200°F to 1500°F).

Since typical fixed-bed gasifiers including the PyGas™ gasifier are designed to operate below the coal ash melting temperature, less metal volatilization can be expected than from the pulverized coal fired burners which the PyGas™ gasifier is replacing. Therefore, less emissions of trace metals can be expected from the PyGas™ gasifier than from pulverized coal burners and entrained bed gasifiers which operate at very high temperatures.

There exists the potential for the CaSO_4 "blinding" of CaS crystals formed through the reaction of calcined lime and H_2S within the gasifier vessel. Since the potential of CaS existence in the solid waste product from the gasifier could eventually lead to the release of H_2S to the atmosphere, consideration of several hydration options is being planned for this GPIF project. This approach involves the quenching of hot gasifier solid waste directly in an oxygenated aqueous tank either under gasifier or atmospheric pressure. This process is being designed to release and react trapped CaS by submerged combustion forming hydrated CaSO_4 .

19. Viability of the PyGas™ Gasification Concept:

There exists significant data to suggest the viability of the two major components which comprise the PyGas™ gasifier, and the use of limestone as a sulfur capture agent.

C. Lowell (Wormser Engineering) et al demonstrated as high as 95% sulfur retention by the use of limestone injection with the coal into a "slug flow" pyrolyzer operated at 1600°F and of the same geometry as the one used within the PyGas™ gasifier vessel. Since the PyGas™ coal gasifier operates at from 1300°F to 1600°F in its rapid devolatilization pyrolyzer section, it is expected that the limestone will calcine as it does at these temperatures in any fluidized bed process, and will subsequently form calcium sulfide while in the pyrolyzer section of the PyGas™ gasifier. In this manner, it is expected that the limestone will not "deadburn" at these temperatures as it might be expected to in conventional fixed-bed gasifiers operating at 2300°F . Once CaS is formed along with char in the pyrolyzer, it is further expected that increasing the gasifier operating temperature to 2300°F at the top of the gasifier by combusting pyrolysis gases will not adversely affect the CaS solids since both the METC MGas and the KRW kinetic rate models predict very rapid endothermic gasification and temperature drop to the vicinity of 1500°F within a very short distance within the upper solids bed. Similarly, it is believed that the lower PyGas™ gasifier solids bed region will allow the CaS to oxidize to CaSO_4 since the grate area operates in an oxidizing atmosphere.

J.M. Eakman (Exxon Research) et al identified that alkali metal gasification catalysts increase the rate of steam gasification, promote gas phase methanation, and minimize agglomeration of caking coals in a slugging pilot scale unit whose geometry was very similar to that of the Offeror's proprietary gasifier pyrolysis section.

C.Y. Wen (West Virginia University) et al concluded from their entrained-bed coal gasification modeling that the effect of total pressure increased carbon conversion at any steam to fuel ratio. They also concluded that increasing oxygen to fuel ratios increased carbon conversion at any operating pressure and at an optimum steam to coal ratio. The existence of an optimum steam to fuel ratio is important, because one can obtain the same carbon conversion at a lower oxygen feed by maintaining optimal steam to fuel ratios in the 0.4 to 0.5 range. Moreover, their carbon conversion efficiencies considerably exceeded that required by the pyrolyzer section of the PyGas™ gasifier indicating that acceptably high carbon utilization may be expected thereby minimizing conventional fixed bed gasification air and steam requirements.

H.S. Muralidhara (West Virginia University) et al concluded from their study that after initial pyrolysis kinetic reaction rate increases in direct proportion to calcium content of the coal. This may prove valuable to the Offeror's proprietary gasification process and may serve to explain in part why C. Lowell et al achieved greater than 50% carbon utilization during carbonization.

D.E. Woodmansee et al (General Electric) found that the efficiency of converting coal enthalpy to cold gas fuel value increased by 4% when the steam/air mass ratio was reduced. This is consistent with the Offeror's concept of pyrolysis and cracking control by air flow with minimization of

steam flow, and water spray for gasifier combustion zone temperature control in lieu of steam injection.

E. J. Nemeth et al (U.S. Steel Corporation) pilot scale results showed that the desulfurization of coal-derived gas at 1500 to 1770 °F is feasible. They found that desulfurization of the hot reducing gas initially exceeded 97% removal of H₂S with dolomite.

C.Y. Wen et al (West Virginia University) stated that the understanding of coal pyrolysis is very important in view of the potential of the process to take advantage of (1) the phenomena of rapid pyrolysis and (2) obtaining higher yields of gaseous hydrocarbons by the application of pressure and hydrogen atmosphere. It was also stated that pilot plant studies of Union Carbide showed that of gaseous hydrocarbons is improved significantly under high partial pressure of hydrogen. The char-gas reactions that take place during the second stage following the pyrolysis reaction may be classified into two distinct categories, namely volumetric reactions and surface reactions. Thus, diffusion is an important step in heterogeneous char-gas reactions. Higher hydrogen partial pressure improves the carbon conversion in the first stage of fast pyrolysis. For this reason, the Offeror intends to provide for the introduction of steam into the pyrolysis section of the gasifier along with the coal, limestone, and air.

Squires et al experiments showed that there is practically no liquid tar in the volatiles at temperatures above 1650°F when the gasification was done in a hydrogen partial pressure of 100 atm. and at a rapid rate.

If in the char-oxygen reaction (burning of char), the temperature and/or the particle size decrease substantially, the reaction may proceed toward the chemical; reaction control regime, and it may take place uniformly throughout the internal pore surfaces of the particles. This observation may allow the Offeror's gasifier to operate at lower steam to coal ratios in the gasifier combustion zone without experiencing the ash melting problems of conventional fixed bed gasifiers.

Wen observed that very little study has been done on the relative reactivities of different coal-chars in char-steam reactions. Jenson, Klei et al, and Kayembe et al each demonstrated that carbon-steam or char-steam reaction is chemical reaction controlled for smaller carbon/char particles (roughly <500 micron) and at temperatures up to 1800°F. At these conditions, the reaction occurs uniformly throughout the interior of the pore surfaces of the solid particles. Wen concluded that the phenomena of pyrolysis, particularly those of rapid and flash pyrolysis are yet to be understood well. The GPIF will be an excellent way to correct this deficiency.

Since the PyGas™ gasification process also is intended to crack gaseous tars, it is expected to result in significantly less tar sulfur related sulfur bypass of the hot gas cleanup system, and far less concern for operational constraints relating to tar and carbon-black thermophoresis pluggage potential downstream of the gasifier than currently exists for current fixed-bed gasifiers.

The anticipated condensation of volatilized alkali onto the coal ash within the gasifier where it can be stabilized by the aluminosilicates in the ash represents yet another very substantial technological advantage of the PyGas™ coal gasification process.

Another technical advance of PyGas™ type of coal gasification process was demonstrated by Acurex under DOE contract. Less ammonia conversion to NO_x was reported for low Btu gas combustion than for medium Btu gas. When combusted in a rich/lean mode, as much as 95% NO_x reduction resulted. Additionally, when low Btu PyGas™ gasifier coal gas is also combusted in the burners of an existing retrofit/repowered boiler with turbine exhaust gas, a significant amount of NO_x reduction by "reburning" can also take place. West Texas Utilities San Angelo plant demonstrated a 50% reduction in the NO_x that had been produced by the gas turbine when operated in the fired gas turbine and fired boiler combined cycle mode.

Yet another technical advance which the PyGas™ gasifier enjoys over other fixed-bed gasifiers is its consistently relatively high raw gas exit temperature (1200°F to 1500°F). Typical coal gasifiers cannot control their raw gas exiting temperatures due to the evaporative process of the entering coal's moisture which can vary daily with coal moisture content.

Particulate carryover from the PyGas™ coal gasifier is expected to be very low since none of the coal feed fines can bypass the gasification process as with most fixed-bed coal gasifiers.

Existing boilers fired with high gas mass flows as is the case for a fired combined cycle retrofit/repowered boilers with low Btu PyGas™ gasifier coal gas produce more burner turbulence, better mixing and low CO emissions.

The final technical advance is the ability of the PyGas™ gasifier to produce exit gas temperatures very near the optimum for hot gas cleanup systems. This is in deference to the very hot slagging gasifiers which must either quench their gas (very inefficient), or indirectly cool their gas which shifts more heat to the less efficient Rankine thermodynamic cycle and away from the more efficient Brayton thermodynamic cycle.

Therefore, the the PyGas™ gasifier coal gasification process claims the following TECHNICAL ADVANCES:

1. Operates even on eastern high caking bituminous coals.
2. Cracks tars, promotes high temperature thermophoresis avoidance
3. Liberates tar related sulfur promoting higher hot gas cleanup system sulfur capture.
4. Condenses and captures volatilized alkali with in-bed ash-aluminosilicate bonding.
5. When low Btu PyGas™ gasifier coal gas is fired in a gas turbine, then fired in a retrofit/repowered existing boiler on turbine exhaust gas, the an emission of rate less than 0.1 lb/MMBtu of NOx is anticipated even without an SCR.
6. High raw gas exit temperatures consistent with the needs of hot gas cleanup systems.
7. Low particulate carryover since coal feed fines cannot bypass the gasification process.
8. Low Btu coal gas combustion increases turbulence and mixing in existing burners producing low CO emissions.
9. Not requiring significant raw gas cooling (with associated Btus going to the Rankine cycle) keeps more Btus in the more efficient Brayton cycle.

All the above result in the following emission expectations for SO₂, NO_x, CO, and particulates:

- 99.5+% sulfur removal capability with hot gas cleanup (zinc ferrite type) due to the release of tar bound sulfur by cracking within the PyGas™ gasifier vessel.
- 97.5+% reduction of oxides of nitrogen due to low Btu gas firing in an auxiliary steam generator with exhaust gas ducted back to the existing precipitator.
- While CO per cent reduction expectations vary with each individual application, existing boilers fired with high gas mass flows as is the case for a fired combined cycle retrofit/repowered boiler produce more burner turbulence, better mixing and low CO emissions.
- 99.9+% particulate removal mostly within the PyGas™ gasifier vessel since coal feed fines do not bypass the gasification process as with most fixed-bed coal gasifiers.

The following test data illustrates the flexibility of the PyGas™ coal gasification process. The operating temperature of the pyrolyzer section is controlled by the quantity of air flow to it. The anticipated operating temperature range is from 1300°F to 1600°F which requires from approximately 14% to 27% of stoichiometric air for pyrolysis.

In 1973, Menster, et al illustrated "rapid pyrolysis" as a method of carbonizing many different U.S. coals. In 1982, Lowell, et al showed strikingly similar results when operating their pyrolyzer on caking bituminous coal with air as shown in the devolatilization versus operating temperature figure.

The pyrolyzer turndown tests showed that very high rates of organics being driven into gaseous state (approximately 50% by weight) was possible over a very wide operating range while holding operating temperature constant by simply varying air flow to the pyrolyzer.

These most significant developments show conclusively that adding a pyrolyzer such as contemplated by the PyGas™ gasifier increases the gasifier yield by avoiding liquid phase tars, as well as by quickly consuming 50% of the coal in a relatively small fluidized bed vessel operated in the "slug flow" regime.

If all that the PyGas™ gasifier ever did was to condition caking coal to avoid agglomeration, it would no doubt be considered very successful. However, the PyGas™ gasifier actually performs several additional process benefits in the gasification of coal. These include cracking tar, condensing volatilized alkali, preventing coal fines carryover from the gasifier, producing raw gas at temperatures ideal for hot gas cleanup systems, and handling coal of any expected moisture content with no adverse affect on gasifier exit temperature.

Additional air is specifically introduced at the top of the gasifier to raise its operating temperature sufficiently to crack the tars driven to gaseous form during pyrolysis. To do this requires only to add air until the gasses at the top of the PyGas™ gasifier reach approximately 2300 F. The specific coal inorganic fraction fusion characteristics will dictate more precisely the top gas operating temperature just as it does for conventional fixed-bed gasifiers.

As both char and coal gas pass co-currently downward through the PyGas™ gasifier, endothermic reactions predominate thus cooling both from 2300°F to approximately 1500°F by producing hydrogen and carbon monoxide. In so doing, any volatilized alkali have the opportunity to condense onto the coal ash and become tied up by naturally occurring aluminosilicates in the ash, and subsequently are removed from the PyGas™ gasifier along with the ash in the conventional fixed-bed coal gasifier way. This process provides for volatilized alkali condensation and removal on the coal ash while within the PyGas™ gasifier vessel rather than on combustion turbine blades at 1800°F where significant damage can occur.

The PyGas™ gasifier forces all of the incoming coal to pass entirely through the entire pyrolyzer and gasifier sections before it can leave the gasifier. This virtually assures that no coal fines can bypass the gasifier as is commonly the case for any counter-current fixed-bed gasifier with gasifier top coal feed and raw gas removal. This then eliminates concern that coal fines might plug downstream piping due to thermophoresis and tar condensation both well known conventional fixed-bed gasifier realities. It also allows much more flexibility to the hot gas cleanup system mechanical hardware design which up to now has been limited by coal fines and condensible tar carryover concerns.

Since the last stage of the PyGas™ coal gasification process is that of carbon gasification, the raw gas exit temperature will always be very close to the optimum for zinc ferrite types of hot gas cleanup systems, in the 1200°F to 1500°F range. This is a decided advantage as opposed to either the molten slag bottom entrained bed gasifier types which produce raw gas too hot for hot gas

cleanup systems, and conventional fixed-bed gasifiers whose raw gas product is often too cold depending on how much coal moisture had to be evaporated hence cooling down its exiting temperatures.

Irrespective of coal moisture content, the PyGas™ gasifier's raw gas exit temperatures remain nearly constant at near optimum hot gas cleanup temperatures. Conventional fixed-bed gasifiers which have little control over raw gas exit temperatures affected by incoming coal moisture will create significant difficulty for hot gas cleanup system control.

Based upon the significant past success of pyrolyzers (sometimes called "carbonizers") built and operated by several U.S. Government agencies as well as independent private organizations, and owing to the simplicity of merely placing such a device within the confines of a fixed-bed air-blown coal gasifier vessel in such a manner that gravity alone is necessary to move the products of pyrolysis into the conventional gasifier, the decision by the DOE to accept the PyGas™ gasifier as "ready for testing" is quite reasonable.

20. OVERVIEW OF THE PyGas™ PROCESS

Crushed coal (1/4 x 0) is pneumatically conveyed to the pyrolyzer. Upon entry into the preheated pyrolysis cone, the oxygen in the air reacts with the coal to provide the necessary heat to rapidly drive off the volatile content of the coal. The rapid devolatilization of the coal results in gaseous "bubbles" that pass upward through the bed and exit the top of the pyrolyzer tube. This action, along with the continuous feed of air and coal, moves the char/ash granules, at a slower rate than the gases, toward the top of the pyrolyzer. The solids flow over the edge of the pyrolyzer tube, falling by gravity onto the upper fixed bed while the gases disperse into the upper zone of the gasifier and subsequently down through the upper solids bed. Injection of air and steam into the top of the gasifier partially oxidizes the exiting pyrolyzer gases. This raises the mean bulk gas temperature of the upper gasifier zone. The resulting high temperatures crack hydrocarbon compounds that have resulted from pyrolysis. The hot gases in the upper zone of the gasifier then flow co-currently with and through the carbon/ash (char) bed. Gasification of the carbon in the upper bed occurs until the bed temperature (cooling off due to the endothermic gasification reaction) reaches approximately 1300° F to 1500° F.

While the upper gasifier zone gases endothermically cool in the presence of carbon/ash (char) from approximately 2300° F, any previously volatilized alkali is expected to condense onto the char. There it can become chemically bonded to and hence stabilized by aluminosilicates present in the ash as the gases cool to 1300° F to 1500° F.

At this point, gases evolved through the upper bed flow out of the gasifier. The remaining carbon in the char is consumed in the typical fixed-bed gasification manner through the lower bed. Air and steam are introduced through the gasifier grate. Entering oxygen consumes carbon in the lower bed to raise bed temperatures to approximately the ash fusion temperature. As the gases pass counter-current to the char/ash particles, carbon is consumed by endothermic gasification reactions. Gases evolved from the lower and upper beds then combine and exit the gasifier. Air and steam requirements to the grate are controlled to ensure that the ash exiting the gasifier contains less than 5% carbon by weight.

21. THE PYROLYZER

Pyrolysis is the chemical change created by the addition of heat in a reducing atmosphere. Gasification is the phase change from solid to gas also produced by the addition of heat also in a reducing atmosphere. As coal enters any gasifier, it must be heated to gasification reaction temperatures. During heating, volatiles-the light gases (ie CO, CO₂, H₂, H₂S, & NH₃) and condensable hydrocarbons (referred to as tars)-are released. The release of the volatile products is directly affected by the heating conditions. As coal is heated, its volatiles form bubble-cell structures throughout the coal. Under rapid heating conditions (10⁴ °F/sec), the expansion of the volatiles within the bubbles quickly reach high enough pressures to "break" the bubbles and escape before the coal particle expands. However, as the heating conditions decrease to under 10³ °F/sec, the coal particles swell before the pressure within the "volatile bubbles" is high enough to rupture the "bubbles" [2]. The phenomenon of tars forming a sticky surface coating on coal results in adjacent particles "sticking" together and forming an incipient clinker. This phenomenon is known as agglomeration. Air and steam pass around such agglomerated lumps following a path of least resistance. This bypassing results in a diminished gasification reaction since the air and steam cannot reach the unreacted coal contained within the agglomerated lump. When this happens, channeling occurs within a gasifier and its productivity and efficiency quickly diminish.

Rapid devolatilization occurs in the PyGas™ pyrolyzer section. The rapid heating liberates the tars in gaseous form rather than tacky liquid form. Thus, the agglomeration characteristics of highly caking coals from most eastern American bituminous seams becomes irrelevant.

The PyGas™ pyrolyzer resembles the pyrolyzers used by the United States Bureau of Mines to devolatilize, a process sometimes called "carbonization" various coals. In addition to reviewing their empirical relationships, reports produced by Wormser Engineering, Inc. and West Virginia University were reviewed to model the pyrolyzer performance. A major objective of PyGas™ is the rapid devolatilization and maximization of carbon conversion in the pyrolyzer. This, in turn, minimizes air and steam requirements needed to gasify the remaining carbon (char) in the fixed bed gasifier section. Volatiles released, and thus carbon conversion, can be higher than ASTM predictions. The US Bureau of Mines notes that bituminous coal volatile yield peaks at approximately 1300° F if rapid heating is applied. On the other hand, if the heat rate is slowed down, the volatile yield becomes proportional to pyrolysis temperature [3].

Reviewing material from US Bureau of Mines reports and other experimental work has shown that pyrolysis done by rapid heating has a distinct temperature in which maximum carbon conversion is achieved. Therefore, the PyGas™ pyrolyzer will be operated under controlled conditions at the temperature that achieves the greatest carbon conversion.

Once the temperature has been chosen to ensure maximum volatile release, the amount of air needed to provide the pyrolysis temperature and to ensure rapid heating is determined. A study conducted for the Department of Energy under contract No. DE-AC21-78MC-10484 by Wormser Engineering, Inc. found that pyrolyzer temperature is a function of air fed to the pyrolyzer [4]. Hence, an equation to relate pyrolyzer temperature to air feed was derived and incorporated into the math model. Once the air feed rate per unit of coal to the pyrolyzer and carbon conversion is calculated, the composition of the product gases must then be determined. The following reactions occur in the pyrolyzer:

Reaction 1 and 2 : (oxidation of carbon)

Reaction 3 : (reduction of carbon dioxide)

Reaction 4 : (oxidation of hydrogen)

Reaction 5 : (formation of methane)

Reaction 6 : (formation of hydrogen sulfide)

Reaction 7 : (formation of ammonia)

The following assumptions with the above chemical reactions are used to calculate the gas composition at the exit of the pyrolyzer:

1. 90% of nitrogen bound in the coal forms ammonia, (although a link between steam to gasifier and ammonia generation exists, we currently have insufficient data to better correlate this conversion)
2. all of the sulfur forms hydrogen sulfide (even though a small amount of COS is formed, then partially cracked by the PyGas™ gasifier), and
3. methane formation is based on a study conducted by Lurgi under elevated pressure conditions [5].

Mass and heat are balanced using the above reactions to consume all the oxygen in the feed air and produce the desired pyrolysis temperature. The gas composition is then compared against predicted pyrolysis gas composition by the late Dr. C.Y. Wen, formerly of the Chemical Engineering Department at West Virginia University [6].

Pyrolysis Predicted Gas Composition
(volumetric percentages)

	WVU	PyGas™
CO	27.15	23.38
H ₂ O	3.50	2.03
H ₂	18.55	19.50
CH ₄	3.74	4.75
CO ₂	4.71	4.16
N ₂	40.92	43.73
H ₂ S	0.66	1.02

By virtue of agreement, assumptions and equations within the math model were believed to be reasonably accurate. In all cases developed with the math model and subsequently presented in technical papers, the results shown above were held constant since the pyrolysis performance shown above is believed to be maximized.

22. UPPER ZONE OF THE GASIFIER

Gases and solids exiting from the pyrolyzer are approximately 1300° F - 1600° F. These temperatures are too low for the gasification reactions to rapidly proceed and for exiting tars produced in the pyrolyzer to "crack." Temperatures are therefore raised in the upper zone of the gasifier by the simple introduction of air and steam. Maximum temperatures within this zone are set by the ash fusion characteristics of the coal. Exceeding this upper temperature limit causes an unwanted slagging environment within the gasifier. In the case of gasifying Pittsburgh #8 coal, the maximum temperature is approximately 2300° F. To achieve this temperature, the oxygen within the air combines with the combustible gases exiting the pyrolyzer. Steam is used as an inert medium to control peak temperatures or enhance hydrogen production. Since gases are more reactive than solids, the char and ash particles exiting the pyrolyzer are merely heated and fall unreacted to the upper gasification bed.

The combustible gases exiting the pyrolyzer consist of carbon monoxide, hydrogen, methane and a small quantity of condensable tars. The resulting high temperatures from the addition of air "crack" the condensable tars and methane. Any oxygen not consumed by the methane and tars is consumed by hydrogen and carbon monoxide to form water vapor and carbon dioxide, respectively. The following reactions are incorporated into the math model to predict gas composition after partial oxidation:

Reaction 8 : (oxidation of methane)

Reaction 9 : (oxidation of carbon monoxide)

Reaction 10 : (oxidation of hydrogen)

The first reaction is controlled by the formation rate of methane in the pyrolyzer. However, reactions (9) and (10) are a function of temperature and partial pressures of the gaseous constituents in the upper zone.

23. UPPER BED GASIFICATION

The upper zone oxidation results in peak temperatures of 2300° F when gasifying Pittsburgh #8 coal. This is high enough for the following endothermic gasification reactions to rapidly proceed:

Reaction 11 and 12 : (gasification of char)

$$\text{Heat Absorbed} = 74,196 \text{ Btu/mol}$$

The following rate equations by METC [7] and KRW [8] were compared to determine which set would be used in the mass and energy balance to predict the gases evolved in the upper gasification bed.

Rate equation for reaction 11:

Used by KRW:

$$(1) \text{rate} = k_2[\text{C}](K_2 P_{\text{H}_2\text{O}} / (K_2 P_{\text{H}_2\text{O}} + P_{\text{H}_2}))$$

Used by METC:

$$(2) \text{rate} = 930e^{-45000/RT}[\text{C}](P_{\text{H}_2\text{O}} - P^*_{\text{H}_2\text{O}})$$

where:

$$k_2 = 0.18 \cdot f_{\text{RR}} e^{48,200/R \cdot (1/1255 - 1/T)} (1 + 0.5/K_2) \text{ hr}^{-1}$$

f_{RR} - relative reactivity for coal compared to coke

breeze at 1800° F - 3.2 for Pittsburgh #8 coal

R - universal gas constant

T - absolute temperature (K)

$[\text{C}]$ - concentration of carbon

$$K_2 = 2.25 \times 10^6 e^{-42,600/RT}$$

$P_{\text{H}_2\text{O}}$ - partial pressure of water vapor

$$P^*_{\text{H}_2\text{O}} = P_{\text{H}_2} \cdot P_{\text{CO}} / e^{(17.29 - 16330/T)}$$

P_{H_2} - partial pressure of hydrogen

P_{CO} - partial pressure of carbon monoxide

Rate equation for reaction 12:

Used by KRW

$$(3) \text{rate} = k_1[\text{C}](K_1 P_{\text{CO}_2} / (K_1 P_{\text{CO}_2} + P_{\text{CO}}))$$

Used by METC

$$(4) \text{rate} = 930e^{-45000/RT}[\text{C}](P_{\text{CO}_2} - P^*_{\text{CO}_2})$$

where:

$$k_1 = 0.06 \cdot f_{\text{RR}} e^{48,200/R \cdot (1/1255 - 1/T)} (1 + 0.5/K_1) \text{ hr}^{-1}$$

f_{RR} - relative reactivity for coal compared to coke

breeze at 1800° F - 3.2 for Pittsburgh #8 coal

R - universal gas constant

T - absolute temperature (K)

$[\text{C}]$ - concentration of carbon

$$K_1 = 5.86 \times 10^3 e^{-27,000/RT}$$

P_{CO_2} - partial pressure of carbon dioxide

P_{CO} - partial pressure of carbon monoxide

$$P^*_{\text{CO}_2} = P_{\text{CO}}^2 / e^{(20.92 - 20280/T)}$$

P_{CO}^2 - partial pressure of carbon monoxide squared

Partial pressures of the gases were varied to show that general agreement in the two equations can be obtained for a variety of conditions. At higher temperatures, the KRW rate equation predicts faster carbon conversion in reaction (11) than the METC (MGAS) equation. Also, the KRW equation predicts that the carbon-steam reaction will proceed below 1200° K (approx. 1700° F), while the METC (MGAS) equations show that this gasification reaction essentially quits below 1200° K (approx. 1700° F). While usage of the KRW equations results in a more efficient gasifier because of the higher conversion of carbon to gases at higher temperatures, only actual operation of the PyGas™ gasifier will demonstrate such potential rate limits.

Again, comparison of these two equations were checked over a range of gas partial pressures. Similarly as in the case of the carbon-steam reaction, the METC (MGAS) rate equation shows that gasification reactions substantially diminish below 1200° K (approx. 1700° F).

Both sets of equations were incorporated in a mass and energy balance to compare the results of the KRW rate equations versus the METC (MGAS) rate equations. Assuming enough air is added into the top of the gasifier to raise the gases and solids at the top of the upper gasification bed to 2300° F, and the gasification reactions proceed until the upper bed cools to 1500° F. The gases exiting the gasifier from the upper bed have a higher heating value of 152.6 Btu/scf using the KRW rate equations and 145.5 Btu/scf using the METC (MGAS) rate equations.

24. LOWER BED GASIFICATION

The gasification reactions that occurred in the upper bed resulted from the gas flowing co-currently with the bed. However, all of the available carbon is unable to be gasified in the upper bed due to the requirement to adhere to peak operating temperature limitations specific to each particular coal ash characteristic. This then results in the need for a lower bed to gasify the balance of the carbon. In the lower bed, the gasification reactions occur with the gases flowing counter-currently to the bed as is the case with most conventional fixed-bed gasifiers. Air and steam are introduced into the ash grate of the gasifier. The air/steam mixture comes in contact with the exiting ash to cool the ash down. Upon reacting with available char, all of the oxygen is consumed to form carbon dioxide and raise bed temperatures to allow the gasification reactions to begin. Once again, peak bed temperatures are controlled by the injection of steam with the air. Once the bed temperatures rise, the gasification reactions (11) and (12) proceed until heat absorbed during these reactions cools the lower bed to 1500° F. The resulting gas combines with gases evolved from the upper bed and both subsequently exit the gasifier. Air and steam requirements for the lower bed are based on the amount of carbon conversion in the pyrolyzer and upper bed and on the need to keep carbon in the exiting ash to less than 5% by weight.

25. MATH MODEL PREDICTIONS

A math model was developed to predict PyGas™ performance as the amount of air and steam injected into the top of the gasifier is varied. As mentioned above, the pyrolysis section was held constant over the cases to provide maximum carbon conversion in the pyrolyzer. The following assumptions were used to obtain the results

1. The ash contains 5% carbon.
2. Peak combustion zone temperature in the gasifier is 2300° F.
3. Gasification reactions continue until bed temperature reaches 1500° F.

4. Temperature and gas composition are uniform along the radial direction.
5. Gas and solid temperatures are equal at every point in the gasifier.
6. The process as modeled is adiabatic.
7. Pressure throughout the gasifier has been held constant.
8. The ash composition is simplified as SiO₂.
9. Minimum Steam-to-Air ratio to grate of 0.4.

The amount of air added in case 1 resulted in the ability to reach upper zone temperatures of 2300° F without the addition of steam to the top of the gasifier. As more air is added to the top of the gasifier, additional steam must be added to keep temperatures from exceeding 2300° F. As the air-to-coal ratio at the top of the gasifier increases, total steam-to-coal ratio to the gasifier increases. As the air-to-coal ratio to the top of the gasifier increases, the amount of air needed for lower bed gasification decreases. The total amount of air for pyrolysis and gasification remains relatively constant over the range of upper area air-to-coal ratios. Carbon conversion can be optimized. As would be expected, as the amount of top air increases, the carbon conversion in the upper bed increases and the lower bed decreases. The amount of moisture in the product gas and the higher heating value of the product gas, respectively, are a function of top air-to-coal ratio. As the amount of air to the top of the gasifier increases, steam needed to maintain gasifier peak temperatures increases. The result is a gas with a large amount of moisture and a low heating value. Additionally, peak performance should be gained by operating the PyGas™ gasifier with minimal amount of steam to gasify the coal. Table 10 illustrates the gas constituents exiting the pyrolyzer, exiting the upper gasifier bed, exiting the lower gasifier bed, and finally the combined raw product gas.

Table 10
Predicted Gas Compositions at Various Stages in the PyGas™ Gasifier
Using DOE - CCT4 Reference Coal Analysis
(volumetric percentages)

COAL GAS CONSTITUENT	PYROLYZER EXIT	UPPER GASIFIER EXIT	LOWER GASIFIER EXIT	COMBINED RAW PRODUCT GAS
CO	23.8	27.39	23.51	26.34
H ₂	19.77	17.59	15.33	16.98
CO ₂	3.94	1.8	6.08	2.95
H ₂ O	2.14	2.35	17.49	6.43
CH ₄	4.70	0.00	0.00	0.00
H ₂ S	0.91	0.57	0.00	0.42
N ₂	43.31	49.13	37.14	45.90
Tars	<1.0	<0.1	<0.1	<0.1
Alkali (ppmv)	<.1	<.1	<0.01	<0.01
Temp (°F)	1300	1500	1500	1500
HHV (Btu/scf)	198	151	134	144

26. CONCLUSIONS

The PyGas™ coal gasification process promises to alleviate previous limitations in the type of coals that can be effectively gasified in an air-blown, fixed-bed gasification system.

1. Caking coals can be gasified without the adverse effects of sticky tars which have historically resulted in agglomeration in fixed-bed gasifiers.
2. It incorporates features to eliminate (by cracking) tar formations from exiting the gasifier and plugging downstream piping and equipment.
3. It provides a bed of ash on which volatilized alkali can condense and become retained by aluminosilicates either contained within or added to the coal ash.
4. By cracking sulfur containing tar formations, a previous concern of hot gas cleanup system sulfur bypass is eliminated.
5. High moisture containing coals can be gasified without lowering the gasifier exit temperature which would otherwise adversely affect the hot gas cleanup system, and without excessive exit gas moisture which can otherwise exceed turbine compressor surge margin limitations.
6. In contrast to slagging gasifiers, coals with high or low ash fusion characteristics can be gasified in this air-blown gasifier.
7. The exit temperature allows for optimum performance of the hot gas cleanup unit to remove sulfur compounds.
8. Utilized in concert with hot gas cleanup and a combination of auxiliary steam generator combustion followed by flue gas ducting back to the existing boiler precipitator breeching, emissions of SO₂, NO_x, and CO₂ are expected to be the lowest ever achieved by an IGCC system.

The result is expected to be a clean, low-Btu gaseous fuel of approximately 150 Btu/scf at 1500° F, suitable for firing gas turbines, power boilers, and other combustion processes.

27. Description of the PyGas™ Gasifier

Coal is crushed and pneumatically conveyed with air and steam into the bottom of the pyrolysis reactor tube located in the center of the gasifier. Once in the pyrolyzer, the coal becomes rapidly heated to approximately 1600F, where its volatile content and some of its fixed carbon is converted into gaseous fuel (hydrogen, carbon monoxide, and methane).

Within the pyrolyzer tube, the gaseous fuel forms bubbles which rise to the top of the pyrolyzer tube in slug flow fashion gradually moving the remaining carbon and ash char granules upward

until they too exit the top in fountain fashion where they fall due to gravity onto a fixed bed of carbon and ash char solids.

More air and steam is introduced into the top of the gasifier to further increase the temperature to approximately 2300F. This increases the kinetic rates of endothermic reactions to consume more of the fixed carbon in the fixed bed of char. As the gaseous products of hot pyrolysis gas and char solids pass co-currently downward through the gasifier, more carbon in the char converts to gaseous carbon monoxide endothermically cooling the products to approximately 1300F to 1500F.

The remainder of air and steam is introduced through the rotating ash removal grate to both cool the grate and consume any remaining carbon in the ash prior to ash disposal out the bottom of the gasifier.

The resulting hot raw coal gas exiting the gasifier is rich in hydrogen and carbon monoxide.

28. Unique Features of the PyGas™ Gasifier

The aforementioned proprietary pyrolysis-gasification process and device (although comprised of two previously singularly well proven concepts) is a genuine technological breakthrough in the coal gasification industry. Its unique configuration and process (unlike any other gasifier) allows all coal types and characteristics to be utilized in a very simple inexpensive gasification device. Following are several of its unique features:

28.1 Run of Mine Coal

All previous fixed bed gasifiers were confined to the use of carefully graded lump coal sizes (examples include Lurgi and Wellman Galusha). This meant that much of the coal is either wasted, or must be separated (at considerable expense) and briquetted in order to be utilized.

The PyGas™ gasifier uses crushed coal. It therefore uses all of the cheapest run of mine coals available without any costly coal sizing and briquetting equipment.

28.2 Air Blown

Most coal gasifiers currently under serious industry consideration require very expensive air separation plants to provide pure oxygen to their gasifier (examples include Texaco, Shell, & Dow).

The PyGas™ gasifier is designed to use air directly without the added expense of an oxygen production facility. Virtually all of the gas turbine manufacturers have agreed that the hot raw gas produced by the PyGas™ gasifier is acceptable for combustion in their equipment.

28.3 Caking Coals

Previous fixed bed gasifiers have a long history of operational difficulties when attempting to utilize highly (or even mildly caking) coals. Unfortunately, most eastern bituminous coals are of this caking type.

The PyGas™ gasifier avoids the agglomeration problems initiated by sticky tar and asphaltine formations by completely changing the process by which coal tar is vaporized and subsequently cracked to hydrogen and carbon monoxide within the gasifier. This is considered by some to be the single greatest the PyGas™ gasifier advancement to fixed bed gasification.

28.4 Tar Cracking

Previous fixed bed gasifiers produced nasty tar condensibles which historically plugged many downstream coal gas handling equipment. In addition, it has been found that the sulfur in such tar is not removed by hot gas cleanup systems. This phenomenon has been a great setback to fuel cell advocates who require extremely high sulfur removal efficiencies for successful adaptation to future electrochemical power production concepts.

The PyGas™ gasifier assures complete cracking of coal tar at the high temperature transition from pyrolysis to gasification. This means that tar free gas exits the gasifier. In turn, this also opens the door to the PyGas™ gasifier applications to fuel cell combined cycles which potentially can double the efficiency of coal fired utility power plants (cutting global warming greenhouse carbon dioxide gas by one half).

28.5 Volatilized Alkali Control

Sodium and potassium sulfates have been known to condense on gas turbine blades creating unwanted corrosion and deposits which adversely affect blade life and operating availability. It is known that fluidized and slagging gasifiers produce from one to three orders of magnitude more volatilized alkali than fixed bed gasifiers. To date, the removal method of choice has been to spray cool the coal gas to condense out such harmful products. This significantly adversely affects efficiency and creates a water pollution concern.

The PyGas™ gasifier operates like a fixed bed gasifier in its final gasification stage, so it will not emit significant volatilized alkali. In addition, the PyGas™ gasifier enhances catalytic alkali condensation and reformation due to the presence of coal ash containing significant quantities of catalyzing aluminosilicate mineral species where condensation occurs.

28.6 Minimized Ammonia Production

Ammonia yield in gasification processes is maximized by the use of large amounts of steam. The configuration of previous fixed bed gasifiers exacerbates this problem since coal moisture is evaporated in the final stages of coal gas generation resulting in relatively high coal gas moisture and ammonia concentrations and subsequent fuel nitrogen related NOx emissions.

The PyGas™ gasifier promotes the consumption of moisture via endothermic reactions due to its process configuration in contrast to previous fixed bed gasifiers. This minimizes unreacted moisture and ammonia in its exit gas.

29. Emissions Characteristics

Low Btu coal gasification technology has already demonstrated emission levels which are considerably lower than NSPS for targeted source categories. All gasification combined cycle projects to date have demonstrated very low emission levels superior to either fluidized bed or scrubber technologies.

Now that "greenhouse gasses" and "global warming" concerns abound, it is time to demonstrate integrated gasification combined cycles (IGCC) because these more efficient power cycles can markedly reduce carbon dioxide emissions by some 20% to 25%. Since the PyGas™ coal gasification process produces low (150 Btu/scf) raw gas at approximately 1500°F, when combined with a hot gas cleanup system, it can produce the very highest efficiency of any coal gasification

process to date. The reason for this is that the molten slagging entrained bed gasifiers produce such a high raw gas exit temperature that cooling it to hot gas cleanup system operating temperatures means transferring that sensible heat into the Rankine thermodynamic cycle (most tout steam generation types of hot raw gas cooling).

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NEPA DOCUMENTATION

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1. ANTICIPATED TRACE EMISSIONS FROM GPIF FACILITY

This portion of the NEPA report is concerned with the emission of toxic metal compounds by the gasification process improvement facility (GPIF). The toxic metal emissions and all emissions of the GPIF facility must be put in context of its location. The GPIF facility will be located on site at the Fort Martin facility of Allegheny Power Company, and the energy produced (steam) will be directly used by Fort Martin to produce electricity. The coal used at the GPIF facility will be the same coal used by the utility. Therefore, the emissions of the GPIF will be put in context of the entire facility.

The GPIF assessment will be divided into four section:

- Estimation of the toxic metals content of the raw coal
- Calculation of the emissions from Fort Martin normally
- An estimate of the emission from the GPIF
- A comparison of the two flows

The Fort Martin facility average coal consumption rate is 622,000 lb/h. The GPIF facility will consume about 12,000 lb/h. Additionally, the GPIF facility will produce steam, which will be used to displace some of the steam from the Fort Martin facility, making the overall change in coal consumption, due to GPIF, negligible. However, the partitioning of the metals may change among the various streams, either favorably or unfavorably. The estimate of the partitioning of the metals is the main subject of the comparison.

1.1 Trace Elements in Coal

As the starting point in an analysis of trace element behavior at Fort Martin, the range of possible concentrations in the parent coal must be considered. This is because the behavior of trace elements in combustion systems is strongly dependent on both the concentration of the element and its form in the parent coal. The association of a trace element with a particular mineral can determine its combustion behavior (Boni et al., 1990); for example, elements associated with clays will likely be retained by the clays during combustion, whereas elements associated with pyrite will likely oxidize independently, and may therefore associate with the finer, more difficult to capture fly ash particles. In

general, most of the trace elements are associated with the mineral constituents in bituminous coals, while a significant fraction may be associated with the organic matrix in subbituminous and lignitic coals (Raask, 1985).

The ultimate, proximate, and ash chemical analyses of the current coal used at Fort Martin is presented in Table 1. An analysis of the trace metals content of the Fort Martin coal was not available, therefore literature values were used. The results of a number of studies of the trace metal contents of coals and their forms are presented in Tables 2 and 3. The values of Finkleman (1992) were used for the assessment. The Finkleman values were calculated from an average of 6000 to 8000 coals contained in the National Coal Resources Data System (NCRDS) for the U.S. Geological Survey. The NCRDS values represent the most comprehensive and up-to-date summary of trace elements data on U.S. coals.

Table 1. Fort Martin Coal Analyses (As-Fired Basis)

		%
Proximate	Moisture	1.6
	Ash	15.1
	Volat ile	28.9
Ultimate	Carbon	70.11
	Hydrogen	4.43
	Nitrogen	1.24
	Sulfur	0.93
	Oxygen	8.19
	Ash	15.1
Ash Composition (as the oxide)		
	SiO ₂	55.7
	Al ₂ O ₃	31.8
	Fe ₂ O ₃	4.6
	TiO ₂	1.6
	MgO	0.98
	MnO	0.03
	P ₂ O ₅	0.23
	K ₂ O	2.5
	CaO	0.9

Table 2. Trace Element Concentrations in Pulverized Coals

Element	(A)	(B)	(C)	(D)	(E)
Sb*	1.2	-	1.3	1.1	2
As*	24	20	14	15	10
Ba	170	-	-	150	250
Be*	2.2	2.2	1.6	2	1
B	49	-	102	50	50
Cd*	0.47	0.9	2.5	1.3	1
Cr*	15	20.5	14	15	20
Co*	6.1	-	9.6	7	10
Cu	16	17.8	15	19	20
Pb*	11	-	35	16	20
Mn*	43	100	49	100	40
Hg*	0.17	0.21	0.2	0.18	0.1
Mo	3.3	-	7.5	3	3
Ni*	14	16.9	21	15	20
Se*	2.8	-	2.1	4.1	3
V	22	-	33	20	40
Uranium (238)	2.1	-	-	-	-
Thorium (232)	3.2	-	-	-	2
<p>(A) - Finkelman (1992), mean of at least 7100 coals (except Cd = 6150) from</p> <p>Bold indicates values used in mass balance calculations.</p> <p>(B) - Brooks (1989), mean of 3572 bituminous coals in NCRDS as of 1982.</p> <p>(C) - Ruch et al. (1974) mean of 101 samples Ill. bituminous; as reported in</p> <p>(D) - Swanson et al. (1976) mean of 799 samples bituminous and</p> <p>(E) - Smith (1980), mean value for a "typical" bituminous coal.</p>					
*Hazardous Air Pollutants identified in Title III/Section 112 of 1990 Clean Air Act Amendments

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Table 3. Common Forms of Trace Elements in Coal

Element	Forms in Coal	Ref.
Sb	uncertain - sulfides, organic association, pyrite all possible	1,2
As	pyrite (solid solution), small amount organic association	1,2
Ba	50% organic in bituminous coals; 90%+ in low rank coals	2
Be	predominantly organic association; clays also possible	1,3,5
B	organic association; incorporation in illite also possible	1,3
Cd	replacement for zinc in sphalerite (ZnS)	1,3
Cr	uncertain - clays or chromite?	1,2
Co	sulfides, also incorporated in pyrite	1,2
Cu	chalcopyrite (CuFeS_2)	1,3
Pb	galena (PbS) in high sulfur coals; PbSe also possible	1,3
Mn	incorporation in siderite and calcite minerals	1
Hg	solid solution in pyrite; generally w/fine minerals	1,3,4
Mo	uncertain - sulfides? (correlates w/S in Hungarian coals)	1,3
Ni	uncertain - (sulfides, organic association, clays)	1
Se	70-80% organic - low rank coals; fine pyrite, PbSe also	1,2,3,4
V	clays; some organic association possible; uranium mineral?	1,3
Uranium (238)	some organic, some silicates	1,2
Thorium (232)	rare earth phosphate	1
(1) Finkelman (1992) (2) Finkelman et al. (1990) (3) Raask (1985) (4) Akers (1991) (5) Smith (1980)		

1.2 Emission from Fort Martin Plant Under Normal Operation

Now that the concentration of the trace metals in coal has been estimated, the flow of these metals at Fort Martin can be evaluated. In order to discuss the flow of toxics at Fort Martin, the plant has been divided into five units:

- Coal pile
- Boiler
- Economizer and air heater hoppers
- Electrostatic precipitator
- Stack

Fort Martin is comprised of two pulverized coal-fired boilers with a total generating capacity of 1,107 MW. A block diagram of the facility is contained in Figure 1. At Fort Martin there are two separate pulverized-coal-fired boilers (one CE boiler and one B&W boiler), but they share a common coal source and a common stack. Because of this configuration, we will consider the two units as a combined unit operation.

A NEPA assessment of the Fort Martin facility is not the main goal of this report. This analysis is a basis for evaluation of the GPIF facility. Therefore, the analysis of the Fort Martin facility will be based on an "average" emission level.

1.2.1 Coal Pile

The first unit for the balance is the coal pile. The pile is the first place that the inorganics enter, and there are modifications and losses occurring in this region. For example, all coal constituents begin to oxidize in the coal pile. The oxidation process is a very slow, low temperature combustion process. Among the mineral components that oxidize are sulfides (e.g., pyrite), which react with water and oxygen to form sulfuric acid and iron sulfate. Trace toxic elements associated with sulfides (e.g., lead, nickel, arsenic among others) may, therefore, leach out of the coal and contaminate the runoff water. The degree of leaching will be influenced by the pH of the runoff (i.e., the acidity of the rainfall and the amount of pyrite oxidation occurring.)

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Figure 1. Process flow diagram for Fort Martin.

The most important factors affecting the rate of ambient oxidation of the coal and coal minerals are coal rank, surface area, duration of exposure to air, and temperature. Low rank (subbituminous) coals are more reactive than high rank coals (e.g., bituminous). Small coal particle size, long storage times, and a high ambient temperature contribute to increased degree of oxidation (and potentially increased mobilization of trace elements into the runoff).

There is insufficient data to accurately assess the magnitude of this waste stream. Besides the scarcity of data, the sporadic nature of this stream complicates measurements. For example, the monthly precipitation controls both the flow rate and concentration of trace metals. The lack of data makes estimation of this stream difficult. In addition, the GPIF will not affect the size or composition of the coal pile. Therefore, no significant change will occur due to the addition of the GPIF facility.

1.2.2 Boiler

Coal from the coal pile is first pulverized and then fed to the individual burners of the boiler. Injected with preheated air, the pulverized coal particles devolatilize, ignite, and burn as they travel upward through the furnace. As the coal particles react, the associated mineral matter begins to react as well. Some of the resulting ash particles will attach to boiler walls and eventually fall to the bottom due to excessive mass, load shedding, or sootblowing, eventually becoming bottom ash. Other ash particles - denoted fly ash - are carried out of the furnace with the stack gases and downstream where they can collect on convective heat transfer surfaces, hoppers, or pollution control equipment.

Against this backdrop of coal combustion and major inorganic species transformations, the trace metals contained within the coal will also transform. Some may vaporize, some may concentrate in the fly ash, and still others may be found in the bottom ash. To properly assess the partitioning of trace elements to the effluent streams in coal-fired power plants, the transformations undergone in the boiler must be carefully addressed. For example, an element which vaporizes extensively at the high temperatures of combustion may either condense on small fly ash particles or remain in the vapor phase. In either case, it may be difficult to collect with downstream particulate capture devices. Elements which are relatively non-reactive, on the other hand, may concentrate in larger fly ash particles or the bottom ash, making their removal from the boiler more straightforward.

Because fundamental data are lacking, previous field measurements can be used to provide guidance in assessing trace element partitioning in boilers. Table 4 summarizes the results of several studies conducted during the past two decades. Each column in the table presents results from a specific study. Columns with headings 1, 2, and 3 report the ratio of the concentration of an element in the fly ash to that in the bottom ash. Columns with headings 4, 5, 6, and 7 report the stream with the highest concentration of the element - Fly ash, Fly ash (slightly enriched), Vapor, or Bottom ash.

From the table, it is clearly evident that a range of behavior has been observed for several of the trace elements. For example, although antimony and arsenic are concentrated in the fly ash in all of the studies cited, a range of concentration levels is reported. Sampling differences, differences in power plant operation, and differences in the form of these elements in the parent coal could all account for the observed behavior. The two low values reported for selenium are surprising, as it is expected to vaporize during combustion and subsequently recondense on small ash particles (Finkelman et al., 1990; Meserole and Chow, 1991). Consistent with this, Smith (1980) and Davison both report Se concentrations in the small fly ash particles 4 to 5 x greater than in the large (>20 micron) ash particles for bituminous and subbituminous coal fired boilers.

Based upon this review and Table 4, the partitioning of trace elements in coal fired boilers can be summarized as follows, using the classification scheme employed by Brooks (1989) and Tumati and Devito (1991):

- Class 1 - Equally partitioned: Mn, Ba, U₂₃₈, Th₂₃₂
- Class 2 - Concentrated in the fly ash: Sb, As, Cd, Pb, Mo, B, Se
- Class 3 - Intermediate: Be, Cr, Co, Cu, Ni, V
- Class 4 - Vapor: Hg.

**Table 4. Field Measurements of Trace Element Partitioning
in Coal-Fired Combustion Boilers**

Element	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Sb	2	4	19	F	F	F	-
As	4-5	8	6	F	-	F	F
Ba	-	-	0.9	equal	F	-	-
Be	1.5	1.5	-	-	F	-	F (s)
B	-	-	-	-	V	F	-
Cd	1	6	7	F	-	F	F
Cr	5-6	2	2	F (s)	F(s)	-	F(s)
Co	1	-	1.9	equal	F	-	-
Cu	1	1.5	7	F	F	-	F(s)
Pb	2.5	4	13	F	F	F	-
Mn	< 1	1.3	1	equal	B	-	F(s)
Hg	-	-	2	V	V	-	V
Mo	-	-	-	F	F	F	-
Ni	2	1.5	2.5	F(s)	F	-	F(s)
Se	1	0.9	310	F	V	F	-
V	1	-	1.7	F(s)	-	F	-

Numbers signify ratio of fly ash to bottom ash concentration

F and F(s) signify fly ash and sly ash (slightly enriched)

V signifies an element concentrated in the vapor phase

B signifies an element concentrated in the bottom ash

(1) Davison et al. (1974) - pulverized coal power plant; probably

(2) Tumati and Devito (1991) - 1.5 MW pilot scale, washed

(3) Barrett et al. (1983) - literature survey

(4) Klein et al. (1975) - cyclone fired power plant, Ill. basin

(5) Clarke (1991) - Netherlands power plant

(6) Akers et al. (1989) - literature survey

(7) Brooks (1989) - literature survey

For class 2 elements and Ni, Cu, and Cr, increasing concentrations with decreasing fly ash particle size have been observed (Smith, 1980; Barrett et al., 1983; Davison et al., 1974; Meserole and Chow, 1991). Note that despite differences in partitioning, most of the trace metals *on a mass basis* will be found in the fly ash. This is because the fly ash is generally 80 to 85% of the total ash formed in a dry bottom pulverized coal boiler (Brooks, 1989; Akers et al., 1989). Elements such as Mn which are slightly enriched in the bottom ash will therefore principally exist (on a total mass basis) in the fly ash.

After the combustion process, the ash is collected in several areas. Hoppers are used to collect the bottom ash material falling from the furnace walls. The bottom ash is removed from the hopper by drag or screw conveyors and sent to the ash pond for storage and ultimate disposal.

A mass balance around the Fort Martin boilers is shown in Figure 2. For this figure, both boilers are addressed as one unit operation. The flow of the coal (as received), ash, air, and flue gases is shown. A value of 20% is used as an estimate of the fraction of ash which reports to the bottom hopper.

Figure 2. Boiler mass balance calculation results.

Table 5 contains a mass balance of the trace metal flows indicating both the concentration and flow rates in the various streams. In the first column, the concentration of the element in the coal is given. The second column contains the ratio of the element concentration in the fly ash to the bottom ash, derived from Table 4. The third and fourth columns list the concentration of the various elements in the fly ash and bottom ash streams, respectively. The last two columns list the absolute flow rate in each of the streams.

Table 5. Balance of Trace Element Concentrations Around the Boilers

Element	Coal (ppm)	Conc. Ratio FA/Bottom	Fly Ash (ppm)	Bottom Ash (ppm)	Fly Ash (lb/h)	Bottom Ash (lb/h)
Antimony	1.2	2	8.9	4.4	0.66	0.083
Arsenic	24	5	190	38	14	0.71
Barium	170	1	1133	1133	85	21
Beryllium	2.2	1.5	16	10.5	1.2	0.2
Boron	49	5	388*	78	29*	1.5
Cadmium	0.5	2.5	3.6	1.4	0.27	0.027
Chromium	15	2	111	56	8.3	1.04
Cobalt	6.1	1	41	41	3	0.76
Copper	16	1	107	107	8	1.99
Lead	11	2.5	83	33	6.2	0.62
Manganese	43	1	287	287	21	5.3
Mercury	0.2	20	1.4*	0.07	0.1	0.001
Molybdenum	3.3	1.25	23	18	1.7	0.34
Nickel	14	2	104	52	7.7	0.97
Selenium	3.1	5	25	4.9	1.8	0.09
Vanadium	22	1.5	157	105	11.7	1.95
Uranium (238)	2.1	1	14	14	1.0	0.3
Thorium (232)	3.2	1	21	21	1.6	0.4
*Including vaporized fraction						

1.2.3 Economizer and Air Heater Hopper

After exiting the boiler and the superheater region, the dust-laden flue gas enters the convective heat recovery section of the power plant, where the gas passes through the secondary superheater, vertical and horizontal reheater, primary superheater economizer and air heater. As the hot gases pass the cooler heat transfer surfaces, ash vapor and ash particles may condense and deposit on the tube surfaces. Eventually these ash particles are shed, or removed via sootblowing of the tube surfaces. Hoppers are located in both the economizer and the air heater to collect the resulting ash and fallen deposits.

Figure 3 contains a mass balance around the convective section. A value of 10% is taken for the flow of ash into the air heater and reheater hoppers. Since the temperatures are much lower than in the furnace, it is expected that condensation of vaporized inorganics will occur in this region. However, it is reasonable to assume that the ash in these hoppers will be identical to the ash entering the ESP, because the reduction in temperature between the air heater and the ESP will not affect the condensation reactions. Mercury was the only exception, and all of the mercury was assumed to remain in the flue gas.

Table 6 gives the details of the overall balance for the convective section hoppers. Ash was distributed according to the overall mass flow with no change in concentrations of the trace elements.

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Figure 3. Balance around convective section.

Table 6. Balance Around Air Heater and Economizer Hoppers

Element	Fly Ash In (lb/h)	Fly Ash Out (lb/h)	Fly Ash Out (lb/h)	Fly Ash Out (ppm)	Hopper Ash (lb/h)	Hopper Ash (ppm)
Antimony	0.7	8.9	0.6	8.9	0.07	8.9
Arsenic	14.2	190.5	12.8	190.5	1.42	190
Barium	84.6	1133.3	76.1	1133.3	8.46	1133
Beryllium	1.2	15.7	1.1	15.7	0.12	16
Boron	29.0	388.9	26.3	388.9	2.50	388
Cadmium	0.3	3.6	0.2	3.6	0.03	3.6
Chromium	8.3	111.1	7.5	111.1	0.83	111
Cobalt	3.0	40.7	2.7	40.7	0.30	41
Copper	8.0	106.7	7.2	106.7	0.80	107
Lead	6.2	83.3	5.6	83.3	0.62	83
Manganese	21.4	286.7	19.3	286.7	2.14	287
Mercury	0.1	1.4	0.1	1.4	0.001	1.4
Molybdenum	1.7	22.9	1.5	22.9	0.17	23
Nickel	7.7	103.7	7.0	103.7	0.77	104
Selenium	1.8	24.6	1.7	24.6	0.15	25
Vanadium	11.7	157.1	10.6	157.1	1.17	157
Uranium (238)	1.05	14.0	0.9	14.0	0.10	14
Thorium (232)	1.6	21.3	1.4	21.3	0.16	2.1
Total Ash Flow	74640		67176		7464	

1.2.4 Electrostatic Precipitator

ESPs are used to remove virtually all the remaining ash in the flue gas. The Fort Martin ESPs achieve 99.5% removal of ash entering the ESPs. The mass balance used to evaluate the trace metal flow in this area is shown in Figure 4. While the overall efficiency is assumed to be 99.5%, it is assumed that the efficiency for all the particles less than 3 microns is 95% (5% of the total particles), and the efficiency for particles greater than 3 microns is 99.74% (95% of the fly ash particles) (Smith, 1980). This partitioning is performed because of the known effect of particle size on ESP efficiency.

A trace metal balance around the the ESPs was performed to show the flow of the various metals. Literature estimates were used to give values for a number of factors (Smith, 1980, Turnati and DeVito, 1991). The results of this balance are shown in Table 7. In the first column is the assumed ratio of the concentration of each element in the small to large particles. As seen, many of the elements concentrate in the smaller, more difficult to remove, particles. The flow rates were taken from Table 6 with assumptions that 5% of the boron, 90% of the mercury, and 10% of the selenium is in the gas phase. The rest of the table is calculated given the previous mentioned values about the distribution of small and large (greater than 3 microns) particle, and the removal efficiency for these particles.

Figure 4. Electrostatic precipitator mass balance.

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Table 7. Trace Metal Balance Around the ESP

Element	Concentration Ratio Small/Large	Total Mass Flow (lb/h)	Gas Mass Flow In (lb/h)	ESP Hopper Solid (lb/h)	ESP out Gas (lb/h)	ESP Out Total (lb/h)	Removal Efficiency (%)
Antimony	2	0.597	0	0.593	0	0.004	99.3
Arsenic	11	12.8	0	12.5	0	0.26	98.0
Barium	1	76.1	0	75.8	0	0.38	99.5
Beryllium	1.5	1.05	0	1.04	0	0.006	99.4
Boron	5	25.0	1.4	23.3	1.38	3.05	93.3
Cadmium	2.5	0.239	0	0.237	0	0.002	99.2
Chromium	4.7	7.5	0	7.4	0	0.09	98.8
Cobalt	1	2.73	0	2.71	0	0.014	99.5
Copper	2.5	7.17	0	7.11	0	0.06	99.2
Lead	6.6	5.6	0	5.5	0	0.083	98.5
Manganese	1.6	19.3	0	19.1	0	0.12	99.4
Mercury	5	0.1	0.1	0.01	0.09	0.02	09.8
Molybdenum	4.9	1.54	0	1.52	0	0.019	98.8
Nickel	2.5	7.0	0	6.9	0	0.057	99.2
Selenium	5	1.5	0.2	1.3	0.17	0.35	87.9
Vanadium	2.6	10.6	0	10.5	0	0.088	99.2
Uranium (238)	1	0.941	0	0.936	0	0.005	99.5
Thorium (232)	1	1.433	0	1.426	0	0.007	99.5

1.2.5 Stack

The concentrations of the trace elements in the stack are those exiting the ESP, as defined previously in Table 7.

1.3 Trace Element Behavior in GPIF System

To assess the environmental impact of the GPIF facility, it is necessary to identify the concentrations and mass flows of trace metals in all of the relevant input and effluent streams. These values must then be compared with flows associated with the Fort Martin Power Station to determine the relative impact of GPIF.

There are four major streams associated with the GPIF facility. Two are input streams of coal and limestone, one is the bottom ash effluent, and one is the product gas effluent. The bottom ash, containing spent sulfur sorbent, is subsequently treated in an oxidation unit that produces a moist solid effluent stream. Trace metal concentrations and mass flows for each of these streams are described below.

1.3.1 Mass Balance Around Gasifier

Overall - Overall mass flow balances around the gasifier portion of the GPIF facility were performed as the first step in this analysis. Results of these calculations are shown in the block flow diagram of Figure 5. Values for most total mass flows were taken directly from the CRS Sitrine proposal to DoE/METC for this program. The limestone mass flow was calculated from the coal sulfur content of 0.93% (Table 1) and the assumption that a calcium to sulfur molar ratio of 2.5/1 would be used. The fly ash concentration in the product gas stream was calculated with the assumption that 5% of the total ash flow is entrained as fly ash, based upon operating experience of pilot scale fixed bed gasifiers.

Figure 5. Overall balance at GPIF facility.

Because measurements are lacking, we will assume that the size distribution of the fly ash is equivalent to the size distribution of fly ash produced during combustion of pulverized coal, i.e. 50% < 10 μm and 5% < 3 μm . Note that this is an extremely conservative or worst-case analysis - the actual size distribution of ash produced in the PyGas unit should be larger because of the large coal particle size distribution

Trace Elements - Our analysis of trace metals behavior in the PyGas gasifier is broken down into three sections: 1) the 11 trace metals identified on the Hazardous Air Pollutants list in Section 112 of the 1990 Amendments to the Clean Air Act; 2) the two primary radionuclides contained in coal, uranium, and thorium; and 3) five other trace metals in coal. Thus, each table presented in this sub-section has the metals grouped accordingly.

Using the total mass flows into the gasifier shown in Figure 5 and the trace metal concentrations shown in Table 8, trace metal flows into the gasifier can be calculated.

These results are shown in the final column of Table 8. For all elements except antimony, the contribution of the limestone to the total trace metal input flow is negligible. For antimony, slightly less than half of the inlet flow is provided by the limestone. Coal trace metal concentrations shown in the table were taken from data provided by Finkelman (1992) and are the same values used in the power plant trace metals balance described previously. Trace metal concentrations in limestone are from data provided by Huber (1992) for a typical Mississippi River sedimentary limestone.

Partitioning of Trace Elements in Gasifier - Because of the high maximum temperature encountered in the PyGas™ unit (2300°F), it is reasonable to assume that trace element partitioning will be similar to that observed in a pulverized coal boiler. Thus, three literature studies of trace element partitioning in boilers were combined with two studies of trace element partitioning in fluidized bed gasifiers to provide a broad range of possible values for the PyGas™ gasifier. Although trace elements in coal may partition differently than trace elements in limestone, for the purposes of this analysis it was assumed that they behaved identically.

Partitioning coefficients are presented in Table 9. "Low" represents the lowest value from the combined five studies, "average" represents the median value (or an average value if four of the five values were in close agreement), and "high" represents the maximum observed in the data set. In any given column, a value close to one indicates that there was no enrichment of the metal in the fly ash. Values significantly greater than one reflect enrichment. Note that certain metals in one paper in the set - Tamhankar and Wen (1981) - were considerably skewed toward higher concentrations in the fly ash. Nevertheless, these values were retained as a representation of "worst case" behavior.

Using this partitioning data (Table 9) and the mass flux of trace metals into the gasifier as specified in Table 8, the mass flux out of the gasifier in two streams - fly ash and bottom ash - was calculated for average and maximum partitioning levels. The results of

Table 8. Trace Element Concentrations - GPIF Inlet Streams

Element	Coal Conc. (ppm) ^a	Limestone Conc. (ppm) ^b	Total Inlet Flow (lb/h) ^c
Sb	1.2	14.	0.026
As	24	<4	0.291
Be	2.2	<0.5	0.027
Cd	0.47	<0.5	0.006
Cr	15	<1	0.181
Co	6.1	<0.5	0.074
Pb	11	<2	0.134
Mn	43	-	0.553
Hg	0.17	<0.5	0.002
Ni	14	<0.5	0.168
Se	2.8	<0.5	0.034
Th	3	-	0.039
U	2.1 ^d	-	0.027
Ba	170	2	2.042
B	49	-	0.631
Cu	16	<0.6	0.193
Mo	3.3	<6	0.045
V	22	10	0.273

^aFinkelman (1992), values for typical coal

^bHuber (1992), values for typical sedimentary limestone

^cBased upon inlet flow of each stream and concentrations in this table.
If no data available for limestone concentration, coal concentration
assumed. If upper limit specified (i.e., <x ppm), value of "x" used
in calculations

^dBrooks (1989), value for typical bituminous coal

Table 9. Trace Element Partitioning in Gasifier
 - Ratio of Elemental Concentrations in Fly Ash to Bottom Ash

Element	Low	Average	High
Sb	2	6	19
As	1.5	5	35
Be	1.5	1.5	5
Cd	1	2.5	7
Cr	1.2	2	6
Co	0	1	1
Pb	1.2	2.5	33
Mn	1	1	1
Hg	2	20	*
Ni	1.25	2	6
Se	1	5	310
Th	1	1	1
U	1	1	1
Ba	1	1	1
B	5	5	5
Cu	1	1.5	7
Mo	1.25	1.25	1.25
V	1	1.5	1.7
*100% vaporization is upper limit.			

these calculations are shown in Table 10 for average partitioning coefficients and in Table 11 for maximum partitioning coefficients. In these tables, "c" represents concentration; the subscript "b" represents bottom ash or slag; and the subscript "f" represents fly ash. Using the average partitioning values (Table 10), over 90% of all trace elements except mercury are contained in the gasifier bottom ash. Under "maximum" partitioning conditions, corresponding to the maximum concentration of trace elements in the fly ash, 84% of the metals are still collected with the gasifier bottom ash.

Because the gasifier product gas stream is to be fed to an HRSG at Fort Martin, all trace metals associated with the fly ash will also pass to the boiler. It is assumed that all of the fly ash fed to the HRSG with the gasifier product gas is emitted from the HRSG as fly ash. Thus, the fly ash and trace metals content of the gasifier product gas is assumed to be identical to the fly ash and trace metals content of the HRSG flue gas. Because this product stream is sent to the Fort Martin station ESP, the concentrations and mass flows must be compared to those produced by the pc-boilers for the impact of GPIF to be determined.

1.3.2. Treatment of Bottom Ash

As ash is produced in the PyGas™ gasifier, it is dropped through the bottom and into a quench tank. From this quench tank, the ash stream passes to a reactor vessel where CaS sorbent is oxidized under wet conditions. Inlet and outlet streams to the CaS oxidation unit are shown in Figure 6. Mass flows were calculated by assuming that the ash/sorbent effluent stream contains 15% moisture.

To analyze the environmental impacts of this system, the trace metals concentration in the effluent stream must be determined. this is broken into three sections below.

Air Effluent Stream - Upon exiting the reactor, this stream should consist only of moist or saturated air. Provided that a water mist is not generated, this stream should not contain any detectable levels of trace metals. Additionally, this stream will be fired into the HRSG so that all trace metals will report to the ESP units.

Table 10. Trace Element Partitioning in the Gasifier - Average Partitioning Values Used

Element	Inlet (lb/h)	c_f/c_b	c_b (ppm)	c_f (ppm)	Bottom Ash (lb/h)	Fly Ash (lb/h)
Sb	0.026	6	11.5	69.3	0.020	0.006
As	0.291	5	134.6	673.0	0.230	0.061
Be	0.027	1.5	14.6	21.9	0.025	0.002
Cd	0.006	2.5	3.1	7.7	0.005	0.001
Cr	0.181	2	95.7	191.3	0.164	0.017
Co	0.074	1	41.1	41.1	0.070	0.004
Pb	0.134	2.5	69.2	172.9	0.118	0.016
Mn	0.553	1	306.8	306.8	0.525	0.028
Hg	0.002	20	0.6	11.4	0.001	0.001
Ni	0.168	2	88.8	177.6	0.152	0.016
Se	0.034	5	15.7	78.6	0.027	0.007
Th	0.039	1	21.6	21.6	0.037	0.002
U	0.027	1	15.0	15.0	0.026	0.001
Ba	2.042	1	1133.2	1133.2	1.940	0.102
B	0.631	5	291.9	1459.3	0.500	0.131
Cu	0.193	1.5	104.5	156.7	0.179	0.014
Mo	0.045	1.25	24.7	30.8	0.042	0.003
V	0.273	1.5	147.8	221.7	0.253	0.020

Table 11. Trace Element Partitioning in the Gasifier - Maximum Partitioning Values Used

Element	Inlet (lb/h)	c_f/c_b	c_b (ppm)	c_f (ppm)	Bottom Ash (lb/h)	Fly Ash (lb/h)
Sb	0.026	19	7.6	144.4	0.013	0.013
As	0.291	35	59.9	2094.8	0.102	0.189
Be	0.027	5	12.5	62.4	0.021	0.006
Cd	0.006	7	2.6	17.9	0.004	0.002
Cr	0.181	6	80.4	482.2	0.138	0.043
Co	0.074	1	41.1	41.1	0.070	0.004
Pb	0.134	33	28.6	944.5	0.049	0.085
Mn	0.553	1	306.9	306.9	0.525	0.028
Hg	0.002	9999	0	22.2	0.000	0.002
Ni	0.168	6	74.6	447.6	0.128	0.040
Se	0.034	310	1	355.9	0.002	0.032
Th	0.039	1	21.6	21.6	0.037	0.002
U	0.027	1	15	15	0.026	0.001
Ba	2.042	1	1133.2	1133.2	1.940	0.102
B	0.631	5	291.9	1459.3	0.500	0.131
Cu	0.193	7	82.4	576.9	0.141	0.052
Mo	0.045	1.25	24.7	30.8	0.042	0.003
V	0.273	1.7	146.4	248.8	0.251	0.022

Figure 6. Balance around CaS oxidation unit.

Solid Ash Effluent Stream - The ash contained in this stream shall be representative of the gasifier bottom ash stream. Thus, trace element concentrations are those provided in the penultimate column of Tables 10 and 11. This ash, along with the hopper ash from the ESP and the boilers at Fort Martin, is next sent to a settling lagoon, so the appropriate environmental impact question concerns the concentrations in this stream relative to the hopper streams.

Water Associated with Ash Effluent - Consider the moisture that constitutes 15% of the ash exit stream. The only issue of concern here is the solubility of the trace metals in the reactor moisture. This is a strong function of water pH, as shown in Table 12. Solubility of all of these metals (except Cr) decreases significantly with increasing pH. As long as the pH of the CaS reactor is greater than that of the ash settling lagoon water, therefore, there will be no adverse metal leaching associated with this additional water stream. Based upon

discussion at the program kickoff meeting, the pH of this reactor will be approximately 9. As the values in Table 12 indicate, much less than 1% of the trace metals will be leached.

Table 12. Trace Element Leachability as f(pH)

	% of Metal Leached			
	6	7	9	10
Cd	50	30	0.2	
Pb	0.3	0.1	0.01	
Cu	0.8	0.08	0.01	
Zn	20	3	0.005	
As	0.3	0.04	0.1	
Sb	0.8	0.6	0.5	
Cr	0.015	0.03	1	
Mo	3	3	3	
Mn		x		0.0005x
Ni		x		0.04x
Data from Van der Sloot et al. (1989); DePietro et al. (1989).				

1.3.3. Fate of Trace Elements in Fly Ash

The gas from the GPIF will be combusted in a separate boiler to generate steam for the Ft. Martin facility. The gas will contain one particulate which will be combined with the flue gas from the Ft. Martin plant and put through the ESP.

Table 13 contains an analysis of the trace element partitioning in the flue gas and the ESP hoppers. The analysis was performed exactly the same as for the Ft. Martin facility flue gas, substituting the inputs from GPIF. As can be seen, the overall contribution to the emissions is very small; a total of 0.45 lb/h of additional ash will be emitted compared to 336 lb/h under normal operation.

Table 13. Partitioning of GPIF Fly Ash by the ESP

Element	Fly Ash In (lb/h)	Fly Ash Out (lb/h)	ESP Hopper (lb/h)	ESP Eff. (%)
Antimony	0.006	0.000043	0.006	99.3
Arsenic	0.061	0.001220	0.06	98.0
Barium	0.102	0.00051	0.101	99.5
Beryllium	0.002	0.000012	0.002	99.4
Boron	0.131	0.00815	0.122	93.8
Cadmium	0.001	0.000008	0.001	99.2
Chromium	0.017	0.000204	0.017	98.8
Cobalt	0.004	0.00002	0.004	99.5
Copper	0.014	0.000114	0.014	99.2
Lead	0.016	0.000237	0.016	98.5
Manganese	0.028	0.000176	0.028	99.4
Mercury	0.001	0.000901	0.0001	9.9
Molybdenum	0.003	0.000037	0.003	98.8
Nickel	0.016	0.000128	0.016	99.2
Selenium	0.007	0.000779	0.006	88.9
Vanadium	0.02	0.000166	0.02	99.2
Uranium	0.001	0.000005	0.001	99.5
Thorium	0.002	0.00001	0.002	99.5
Total Fly Ash	90	0.45	89.55	

1.4 Significance of Trace Metal Emission from GPIF

The preceding sections have given a description of the flows at Fort Martin and the proposed GPIF facility. To make a comparison a number of calculations were performed. First, the ash flow into all the hoppers is combined. For the Fort Martin facility, the hoppers are the air heater, economizer, ESP and furnace bottom ash hoppers. For the GPIF, the hoppers are the drum filter discharge hopper and an estimate of the flow to the ESP hoppers resulting from the GPIF fly ash. Combining the hoppers was performed to simplify the comparison, and since all the hoppers are combined on site to be sent to the settling pond. As stated in the analysis, all the ash from the GPIF facility is at least as stable and non-leachable as the normal hopper ash. Therefore the only issue is the change in flow rate. The more important issue is a comparison of the flow of trace metals up the stack. Analyses for the normal facility and the GPIF were performed and can be compared to each other.

Two ways of comparing the flows were addressed. In the first case, the expected case, the total coal input remains constant. This implies that the steam generated by the GPIF makes up for the steam lost by the plant. The second case, the worst case, assumes that the GPIF is 20% less efficient than the Fort Martin Facility. Therefore, the coal flows into the overall facility is 624,400 lb/hr (12,000 for the GPIF, and 2,400 additional firing increment for Fort Martin).

Tables 14a and 14b present the results of this analysis. In Table 14a the expected case is presented. The first four columns present the flow rates into the hoppers and stack for the Fort Martin facility and the GPIF, both at maximum load. The next two columns are the combined flow rate assuming 12,000 lb/h of coal through the GPIF and a 610,000 lb/h through the Fort Martin Facility.

First, the flow rates through the GPIF can be seen to be small compared to the normal flow rates. Second, the distribution between hopper and stack is different for the GPIF. In the case of the GPIF, a larger fraction of the ash and trace metals go to the hoppers for disposal in the settling pond. When the combined flow in the stack is compared to the normal flow in the stack, there is a net decrease in every trace metal and overall flow

Table 14a. Effect of GPIF Facility - Expected Case

Element	Comb. Hoppers Fort Martin Normal Operation (lb/h)	Stack Fort Martin Normal Operaton (lb/h)	GPIF Hopprs (lb/h)	Stack GPIF (lb/h)	Comb. Hoppers Fort Martin with GPIF (lb/h)	Comb. Stack with GPIF (lb/h)	Change Hopprs (%)	Ch'g Stack (%)
Antimony	0.74	0.004	0.03	0.000043	0.75	0.004	1.57	-0.91
Arsenic	14.67	0.26	0.29	0.001220	14.68	0.252	0.05	-1.45
Barium	105.36	0.38	2.04	0.000510	105.37	0.372	0.01	-1.79
Beryllium	1.36	0.006	0.03	0.000012	1.36	0.006	0.05	-1.74
Boron	27.23	3.05	0.62	0.008150	27.33	3.001	0.36	-1.66
Cadmium	0.29	0.002	0.006	0.000008	0.29	0.002	0.14	-1.51
Chromium	9.24	0.09	0.18	0.000204	9.24	0.088	0.03	-1.70
Cobalt	3.78	0.01	0.07	0.000020	3.78	0.013	0.03	-1.78
Copper	9.89	0.06	0.19	0.000114	9.90	0.057	0.02	-1.73
Lead	6.76	0.08	0.13	0.000237	6.76	0.082	0.05	-1.64
Manganese	26.63	0.12	0.55	0.000176	26.66	0.119	0.15	-1.78
Mercury	0.01	0.19	0.001	0.000901	0.01	0.184	6.87	-1.45
Molybdenum	2.03	0.02	0.05	0.000037	2.04	0.019	0.28	-1.74
Nickel	8.65	0.06	0.17	0.000128	8.65	0.056	0.01	-1.70
Selenium	1.56	0.35	0.03	0.000779	1.757	0.341	0.18	-1.71
Vanadium	13.6	0.09	0.27	0.000166	13.61	0.086	0.08	-1.74
Uranium	1.3	0.005	0.03	0.000005	1.30	0.005	0.15	-1.82
Thorium	1.98	0.007	0.04	0.000010	1.98	0.007	0.04	-1.79
Total Fly Ash	92964	336	2531	0.45	92972.5	330	0.009	-1.8

Table 14b. Effect of GPIF Facility - Worst Case

Element	Comb. Hoppers Fort Martin Normal Operation (lb/h)	Stack Fort Martin Normal Operaton (lb/h)	GPIF Hoppers (lb/h)	Stack GPIF (lb/h)	Comb. Hopprs Fort Martin with GPIF (lb/h)	Comb. Stack with GPIF (lb/h)	Change Hopprs (%)	Ch'g Stack (%)
Antimony	0.74	0.004	0.026	0.000043	0.757	0.004	1.96	-0.52
Arsenic	14.67	0.256	0.290	0.001220	14.736	0.253	0.43	-1.07
Barium	105.36	0.379	2.040	0.000510	105.78	0.373	0.39	-1.41
Beryllium	1.36	0.006	0.027	0.000012	1.368	0.006	0.44	-1.36
Boron	27.23	3.052	0.622	0.008150	27.431	3.013	0.74	-1.28
Cadmium	0.29	0.002	0.006	0.000008	0.292	0.002	0.52	-1.12
Chromium	9.24	0.089	0.181	0.000204	9.279	0.088	0.42	-1.32
Cobalt	3.73	0.014	0.074	0.000020	3.796	0.013	0.41	-1.40
Copper	9.89	0.058	0.193	0.000114	9.934	0.057	0.41	-1.35
Lead	6.76	0.083	0.134	0.000237	6.789	0.082	0.44	-1.26
Manganese	26.63	0.012	0.553	0.000176	26.767	0.012	0.53	-1.09
Mercury	0.01	0.186	0.001	0.000901	0.013	0.184	7.26	-1.06
Molybdenum	2.03	0.019	0.045	0.000037	2.047	0.019	0.67	-1.35
Nickel	8.65	0.057	0.168	0.000128	8.686	0.056	0.40	-1.32
Selenium	1.56	0.347	0.033	0.000779	1.573	0.343	0.57	-1.32
Vanadium	13.60	0.088	0.273	0.000166	13.659	0.087	0.46	-1.35
Uranium	1.30	0.005	0.027	0.000005	1.308	0.005	0.53	-1.44
Thorium	1.98	0.007	0.039	0.000010	1.992	0.007	0.42	-1.40
Total Fly Ash	92964	336	2531	0.45	94103	331	1.23	-1.41

by 0.85 to 1.83%. The hoppers show both increases and decreases, ranging from 0.00 to +5.93%. The increases into the hoppers occur mainly because there is a decrease in stack emissions. Some of the increase can be attributed to the CaCO_3 added for SO_2 control.

The worst case scenario is in Table 14b. In this case, since the GPIF boiler is assumed too be 20% less efficient than the Ft. Martin Station boilers, the overall combined emissions must increase, because the overall coal input is increasing from 622,000 to 624,400 lb/h. Once again the main increases are in the hoppers, which is positive. The stack emissions still decrease by 0.13% overall. All but one of the trace elements solid waste increases by less than 1%

In summary, the change in trace element emissions due to GPIF is rather small. In the expected scenario, the stack emissions decrease slightly and the emissions to the settling pond stay about constant. In the worst case, there is a very small, less than 1%, increase in ash emissions, with a 1 to 3% increase in emissions to the land fill.

2. CRITERIA POLLUTANTS

Emissions of criteria pollutants (SO_2 , NO_x , total particulate matter, PM-10, and CO) for the GPIF are based on conventional fixed-bed gasification experience. The following paragraphs summarize the expected emission of each pollutant from the package boiler prior to exhausting the flue gas into the stack at Fort Martin station.

2.1 SO_2 Emissions

It is expected that all of the coal sulfur will be converted to H_2S , COS, or CS_2 during the gasification process. H_2S is expected to constitute greater than 95% of the sulfur products. During tests when limestone was injected with the coal in pyrolyzer tube experiments, up to 95% sulfur retention of volatilized organic sulfur as CaS was achieved lending credence that PyGas™ gasifier may achieve similar reductions. It is therefore likely that greater than 50% of the H_2S will be captured and removed with the gasifier bottom ash. Therefore 10 to 100% of the coal's sulfur will be emitted as SO_2 from the package boiler. So long as the GPIF utilizes low sulfur coal, the combined Ft. Martin Station and GPIF facilities are expected to produce less SO_2 emissions than the Ft. Martin Station currently does and normally will without the GPIF in service.

2.2 NO_x Emissions

The bound nitrogen contained in the coal is converted to molecular nitrogen, tar, ammonia, and cyanide during gasification. N_2 is the predominant product, but NH_3 , HCN, and tar can total 10 to 40% of the coal nitrogen depending on gasifier temperature, steam/air ratio, pyrolysis conditions, and coal type.

Experience with the Riley-Morgan fixed-bed gasifier indicates that NH_3 (200 to 2000 ppm) is greater than HCN (~100 ppm) in the product gas. If tars are cracked in the upper gasifier, tar nitrogen will be converted to either N_2 or HCN. Therefore, the HCN content of the gas leaving the PyGas™ reactor may include more HCN than from previous fixed-bed gasifiers. Whether the fuel bound nitrogen is contained in the tar or cracked to HCN will have little impact on NO_x emissions.

Table 15 shows measured conversion rates of fuel nitrogen to NH_3 in 2-ft diam Wellman-Galusha gasifier. High NH_3 concentrations corresponded to low gasifier outlet

**Table 15. Conversion of Coal Nitrogen to Ammonia
in a 2-ft Diam Wellman-Galusha Gasifier**

Run	NH ₃ Conc. (ppm)	<u>lb Steam</u> Std. cu ft (CO + H ₂)	Coal Nitrogen (wt%)	Molar Conversion of N to NH ₃ (%)
1	1940	2.26	1.54	35.0
2	622	2.19	1.54	12.0
3	385	1.81	1.54	5.2
4	666	1.76	1.54	9.0
5	486	2.19	1.54	5.3
6	658	2.26	1.54	7.2
7	452	1.84	1.54	6.8
8*	1170	7.29	1.08	5.0
*Pure O ₂ as the oxygen source.				

temperatures and high steam flows into the gasifier. Since the PyGas™ reactor will operate at higher outlet temperatures and minimize steam flows, these conversion rates are considered to be an upper bound.

Figure 7 shows the conversion of NH₃ to NO_x using a conventional swirl burner in a refractory-lined furnace. Note that the conversion rate decreases markedly as the NH₃ content of the gas increases, a common observance during oil combustion. The thermal NO_x contribution during these tests was about 100 ppm. The total NO_x emission ranged from 200 to 300 ppm, implying that the conversion of N to NO_x in a gasification or combustion process is less than 10%.

During cracking within the upper PyGas™ vessel, significant ammonia may be reduced to N₂ and H₂ further reducing NO_x emissions potential.

Based on these data, we expect the NO_x emission from the package boiler to be less than 300 ppm (0.4 lb/MBtu). In contrast, the NO_x emission from the Fort Martin boilers are in the range of 525 to 900 ppm (0.7 to 1.2 lb/MBtu). Therefore, the combined Ft. Martin Station and GPIF facilities are expected to produce less SO₂ emissions than the Ft. Martin Station currently does and normally will without the GPIF in service.

Figure 7. Conversion of ammonia to NO_x in a turbulent diffusion flame.

2.3 CO Emissions

The package boiler will utilize a burner capable of burning low-Btu gas having a range of heating values between 100 to 170 Btu/SCF. During periods when poorer quality gas is being produced, the facility will be fired with auxiliary #2 fuel oil. Good combustion will be maintained for all conditions, thus maintaining CO emissions from the package boiler to less than 100 ppm.

3. NEPA ASSESSMENT OF PSIT FACILITIES

PSI Technology Company, a subcontractor to CRS Serrine on the Gasification Process Improvement Facility (GPIF), project DE-RP21-91MC28202, may conduct limited laboratory experimentation during the project. Such experiments would utilize existing laboratory reactor facilities for coal gasification experiments to determine the alkali-sorbent potential of coal ash. Limited experiments may also be conducted to assess the interaction of trace metals within the coal ash, again using existing facilities.

Note that indoor bench-scale research projects or conventional laboratory operation within existing experimental facilities are cited as categorical exclusions to NEPA requirements, as noted in Section B.3.6 of Appendix B, Subpart D, 10 CFR 1021. This PSIT portion of this project clearly falls within this definition.

For completeness, a description of expected emissions from these laboratory activities is described in outline form in the following sections. The format follows that identified by DoE/METC in pages A-10 through A-12 of Part IV, Section J, Attachment A, Exhibit I of the Request for Proposals for this project.

3.1 Brief Description of PSIT Laboratory Facilities to be Used in this Project

If requested by CRSS, PSIT shall conduct bench-scale experiments to assess alkali-ash and/or trace metal-ash interactions during gasification. It is anticipated that a maximum of 3 kg total of coal would be gasified throughout the duration of Phase I. Assuming that work on this project commences in March 1993 and proceeds for two years, the average coal consumption rate in the PSIT facility is 0.125 kg or 0.28 lb/month.

All experiments shall be conducted in existing PSIT bench-scale laboratory facilities. The two reactors being considered for these experiments are extremely small, with coal-feed capacities of approximately 5 g/min coal feed and 0.5 g/min coal feed.

Solid ash deposited on the collection filters is either sent to an analytical lab, or archived at PSIT for future reference. Because the ash is considered a non-hazardous substance, and because of the small (mg) quantities generated, it can also be disposed of in the general office (laboratory) trash.

used for this analysis (data published by Finkelman (1992) for the National Coal Resources Data System (NCRDS) of the U.S. Geological Survey). These were:

Sb	1.2 ppm
As	24
Be	2.2
Cd	0.47
Cr	15
Co	6.1
Pb	11
Mn	43
Hg	0.17
Ni	14
Se	2.8

With a coal ash content of 15%, the following concentrations and emission rates (corresponding to an average ash emission rate of 11 mg/h) are obtained:

Sb	8ppm	0.09 $\mu\text{g/h}$
As	150	1.7
Be	15	0.2
Cd	3	0.03
Cr	100	1.1
Co	41	0.5
Pb	73	0.8
Mn	287	3.2
Hg	1	0.01
Ni	93	1.0
Se	19	0.2

Other Issues: Because of the extremely low values of these emissions, no impact on air quality is expected. As the only water used in these laboratory systems is recirculated cooling water, there will be zero impact on water resources from this project. Local noise levels will not be increased as a result of this project.

Worker Safety: Laboratory workers routinely wear laboratory coats to protect clothing, and use particulate filter masks when handling coal or ash.

Summary: No environmental impact of any type should occur as a result of this small-scale laboratory project.

3.3 Permits Required

No permits are required for operation of the PSIT laboratory facilities. State requirements exempt facilities consuming less than 100 tons of coal per year or having a thermal input of greater than 3×10^6 Btu/h; the PSIT facility consumes approximately 10 lb of coal per year and is rated at 8×10^3 Btu/h maximum.

Note that indoor bench-scale research projects or conventional laboratory operation within existing experimental facilities are cited as categorical exclusions to NEPA requirements, as noted in Section B.3.6 of Appendix B, Subpart D, 10 CFR 1021. This PSIT portion of this project clearly falls within this definition.

3.4 Agency Contacts

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