Process Engineering Division

Shell Gasifier IGCC Base Cases

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PREFACE

This report presents the results of an analysis of two Shell Gasifier IGCC Base Cases. The analyses were performed by W. Shelton and J. Lyons of EG&G.

EXECUTIVE SUMMARY

SHELL GASIFIER IGCC BASE CASES

EXECUTIVE SUMMARY

ASPEN PLUS (version 10.1) Simulation Models and the Cost of Electricity (COE) have been developed for two IGCC cases based on the Shell gasification process. The objective was to establish base cases for commercially available (or nearly available) power plant systems having a nominal size of 400 megawatts (MWe). The simulation models are based on previous simulations (ASPEN Archive CMS Library), available literature information, and Shell published reports. The COE estimates were based on data from the EG&G Cost Estimating Notebook and several contractor reports. These cases can be used as starting points for the development and analysis of proposed advanced power systems.

The cases developed have the following common process sections:

- Coal Prep - coal grinding and fluid-bed dryer to approximately 5% moisture.
- Shell Gasification - entrained flow, oxygen-blown, slagging gasifier.
- Air Separation Unit (ASU) - high pressure process integrated with the gas turbine.
- G gas turbine -W501G modified for coal derived fuel gas.
- Three pressure level subcritical reheat Steam Cycle
  - (1800 psia/1050°F/342 psia/1050°F/ 35 psia).

The approach used for gas cleanup accounts for the major differences between the two cases. For sulfur removal, Case 1 uses cold gas cleanup (CGCU) and Case 2 uses transport desulfurization hot gas cleanup (HGCU). The raw fuel gas cooler section following the gasifier (and integrated with the gasifier and other heat exchangers) is used for generating high pressure superheated steam. This section is followed by a ceramic filter that captures particulates for recycle to the gasifier. The cooled raw fuel gas leaves the filter at a temperature of 640°F for Case 1 and 1004°F for Case 2. In Case 1, the raw fuel gas is further cooled, enters a COS hydrolyzer, and is scrubbed (removes remaining particulates, ammonia and chlorides) before entering the CGCU section. In Case 2, the raw fuel gas enters a chloride guard bed prior to the HGCU section. Sulfur is recovered as elemental sulfur using the Claus process for Case 1 and as sulfuric acid using an acid plant for Case 2.

Process flow diagrams and material and energy balances summaries are shown in Figures 1-4 and COE summaries are given in Appendix A. In Table 1 the overall results obtained for power generation, process efficiency, and COE are compared for both cases.

Table 1 : Shell Gasifier IGCC Base Cases Summary

	CASE 1	**CASE 2**
Gasifier	Shell	Shell
Sulfur Removal	CGCU	HGCU
Gas Turbine Power (MWe)	272.3	272.4
Steam Turbine Power (MWe)	188.8	187.5
Misc/Aux Power (MWe)	48.3	47.7
Total Plant Power (MWe)	412.8	412.2
Efficiency, HHV (%)	45.7	48.0
Efficiency, LHV (%)	47.4	49.8
Total Capital Requirement, ($1000)	566,101	564,963
$/KW	1,371	1,370
Net Operating Costs ($1000)	46,969	42,562
COE (mills/kwh)	42.1	40.7

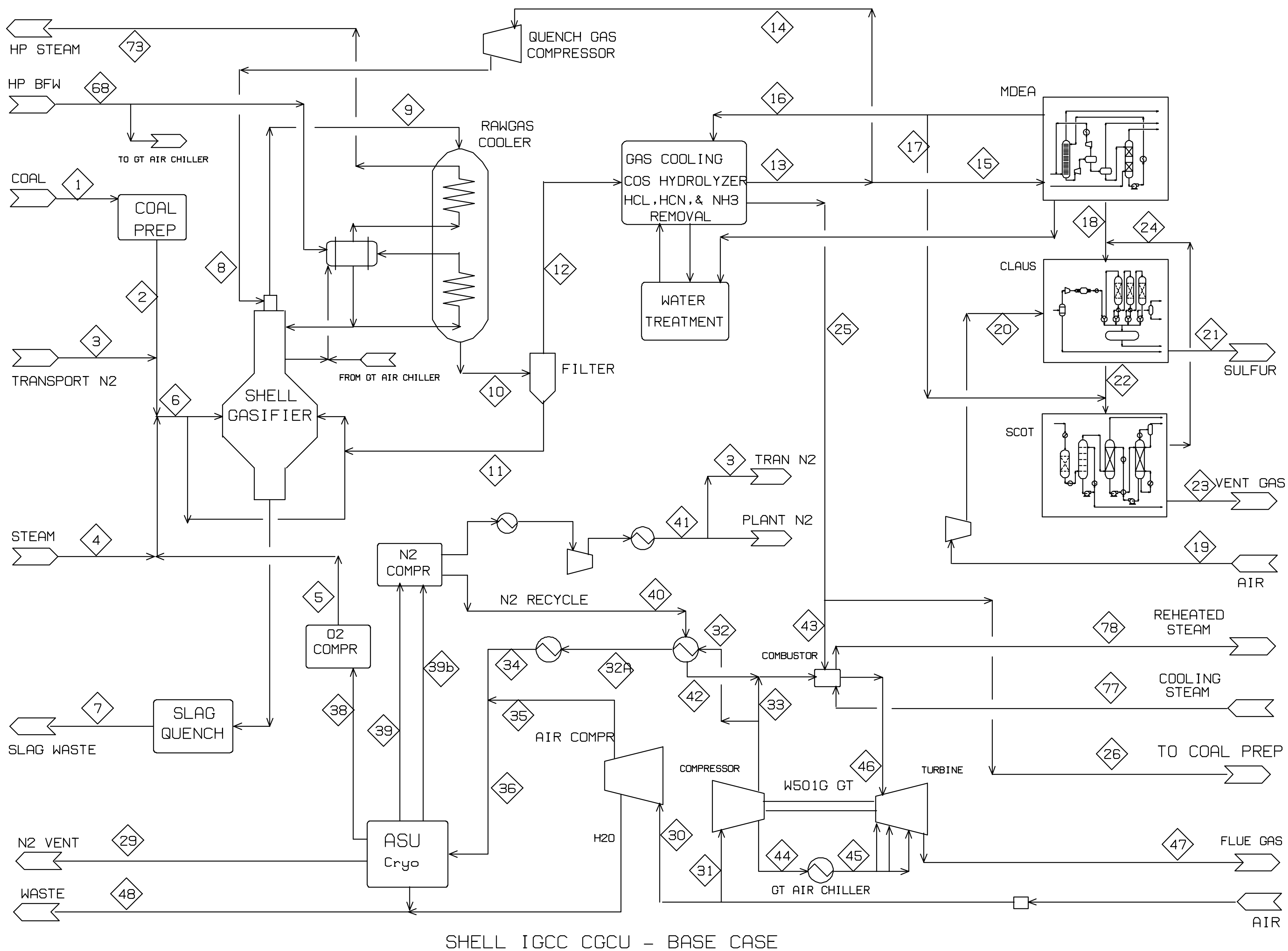

HP STEAM
HP BFW
TO GT AIR CHILLER
COAL
COAL PREP
TRANSPORT N2
STEAM
SLAG WASTE
SLAG QUENCH
SHELL GASIFIER
QUENCH GAS COMPRESSOR
RAWGAS COOLER
FROM GT AIR CHILLER
FILTER
GAS COOLING COS HYDROLYZER HCL,HCN,& NH3 REMOVAL
WATER TREATMENT
MDEA
CLAUS
SCOT
SULFUR
VENT GAS
AIR
TRAN N2
PLANT N2
N2 COMPR
N2 RECYCLE
O2 COMPR
ASU Cryo
N2 VENT
WASTE
AIR COMPR
H2O
COMBUSTOR
COMPRESSOR
TURBINE
W501G GT
GT AIR CHILLER
REHEATED STEAM
COOLING STEAM
TO COAL PREP
FLUE GAS
AIR
SHELL IGCC CGCU - BASE CASE

FIGURE 1A

FIGURE 1B

SHELL IGCC CGCU - BASE CASE

SUMMARY :

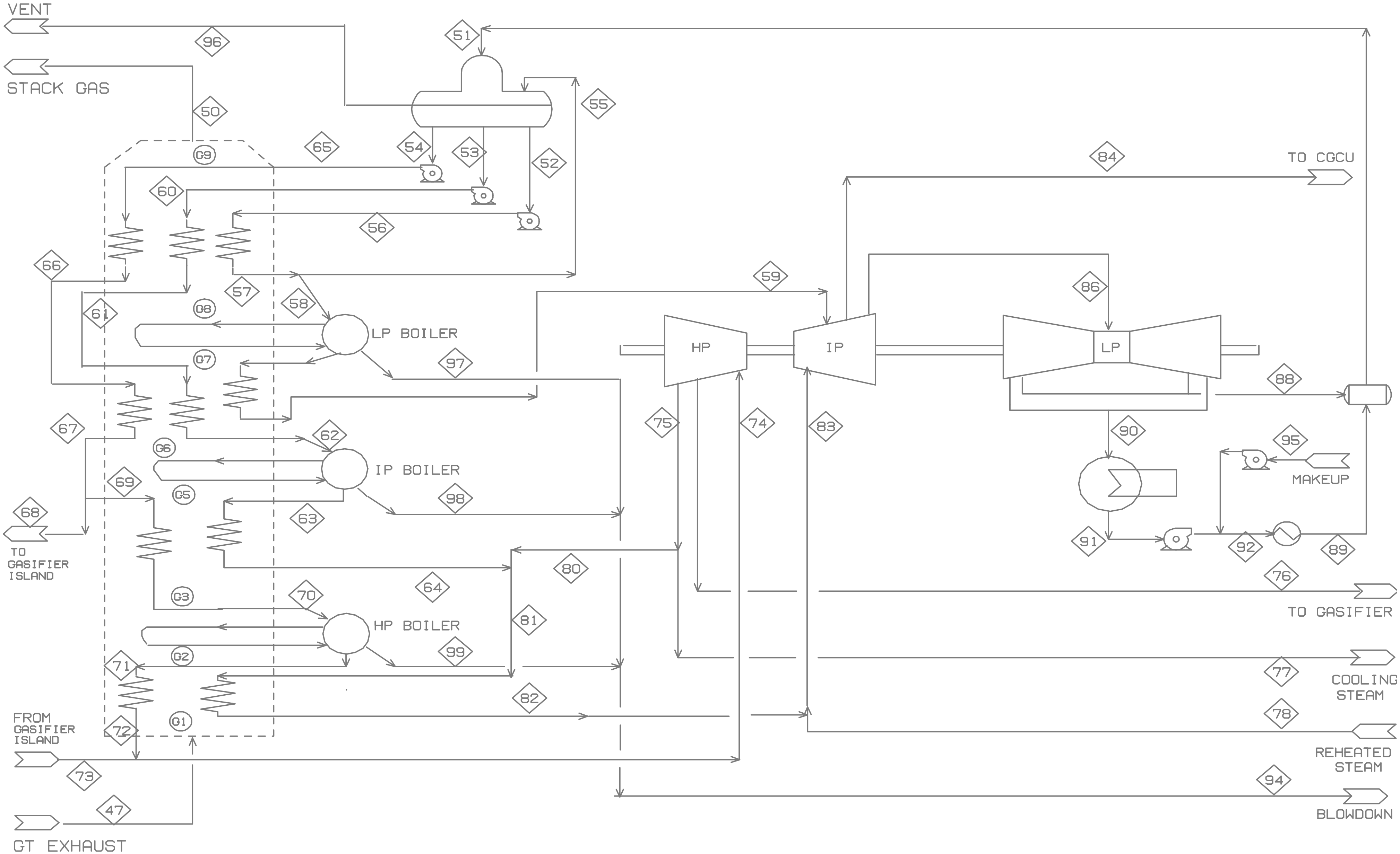
POWER	MWe	EFFICIENCY:	%
GAS TURBINE	272.3	HHV	45.7
STEAM TURBINE	188.9	LHV	47.4
MISCELLANEOUS	35.5		
AUXILIARY (3%)	12.8		
PLANT TOTAL	412.8		

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
FLOW (LB/HR)	264263	248089	18971	7214	213207	488857	26747	194116	656226	656226	1408	654818	647053	194116	452937
TEMPERATURE (F)	59	59	104	694	204.7	144.9	300	123.9	1843.7	640	640	640	100	100	100
PRESSURE (PSIA)	14.7	14.7	400	500	472	370	14.7	370	352.5	347.5	347.5	342.5	327.5	327.5	327.5
H (MM BTU/HR)	-972.6	-155.9	0.1	-39.8	5.4	-193	-62.3	-311.6	-669.3	-964.7	-3.1	-961.6	-1043.9	-313.2	-730.7

STREAM	16	17	18	19	20	21	22	23	24	25	26	29	30	31	32
FLOW (LB/HR)	435249	7243	12078	14529	14529	6496	20730	27354	619	435249	3174	234788	448410	4320000	448410
TEMPERATURE (F)	116	116	160.3	59	161.2	285	430.8	70	70	600	600	62	59	59	813.3
PRESSURE (PSIA)	323	323	18.5	14.7	25	14.7	26.7	17.5	17.5	318	318	91	14.6	14.6	282.2
H (MM BTU/HR)	-701.6	-11.7	-24.2	-0.6	-0.2	-0.7	-44.2	-62.4	-1.7	-628.4	-4.6	-2.6	-18.7	-180.3	65.3

STREAM	32A	33	34	35	36	38	39A	39B	40	41	42	43	44	45	46
FLOW (LB/HR)	448410	3331003	448410	446508	894918	213207	634563	43925	415244	28456	415244	432075	527109	527109	4178319
TEMPERATURE (F)	334.1	813.3	190	203.9	196.9	60	62	60	198.7	105	712	600	813.3	600	2583.1
PRESSURE (PSIA)	280.2	282.2	278	278	278	92	91	265	300	401.8	294	318	282.2	276.6	268.5
H (MM BTU/HR)	10.8	484.8	-5.2	7.3	2.1	-1	-6.9	-0.3	9.3	0.1	63.8	-623.8	76.7	47.9	-114.6

STREAM	47	48	68	73	77	78
FLOW (LB/HR)	4705428	5124	440022	440022	70000	70000
TEMPERATURE (F)	1117.5	59	420	1050	606.2	1055.4
PRESSURE (PSIA)	15.2	15	2116.9	1815	350	342
H (MM BTU/HR)	-1818.1	-35	-2845.9	-2356.5	-388.6	-371.8



SHELL IGCC CGCU – STEAM CYCLE – BASE CASE

FIGURE 2A

FIGURE 2B

Shell IGCC CGCU - Steam Cycle /HRSG Streams

STREAM	47	50	51	52	53	54	55	56	57	58	59	60	61	62	63
FLOW (LB/HR)	4705428	4705428	1034798	285578	199288	816516	273123	285578	285578	12454	12330	199288	199288	199288	197295
TEMPERATURE (F)	1117.5	260	205	217.3	217.3	217.3	286	217.4	286	286	420	218.1	286	420	432.3
PRESSURE (PSIA)	15.2	14.7	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	70.5	410.6	390	370.5	352
H (MM BTU/HR)	-1818.1	-2876	-6925.9	-1907.9	-1331.4	-5454.9	-1805.6	-1907.8	-1887.9	-82.3	-69.3	-1331	-1317.4	-1289.3	-1117.2

STREAM	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78
FLOW (LB/HR)	197295	816516	816516	816516	440022	376494	376494	372729	372729	440022	812751	805536	7214	70000	70000
TEMPERATURE (F)	620	221.1	286	420	420	420	620	629.3	1050	1050	1049.3	606.2	695.7	606.2	1055.4
PRESSURE (PSIA)	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1910.5	1815	1815	1800	350	510	350	342
H (MM BTU/HR)	-1093.8	-5447.6	-5394.5	-5281	-2845.9	-2435	-2342.3	-2132.6	-1996.2	-2356.5	-4352.7	-4472	-39.8	-388.6	-371.8

STREAM	80	81	82	83	84	86	88	89	90	91	92	94	95	96	97
FLOW (LB/HR)	735536	932832	932832	1002832	86350	928812	50648	984150	878164	878164	984150	5882	105986	6540	125
TEMPERATURE (F)	606.2	609.1	1050	1050.4	600	485.1	352.8	151.6	88.8	87.9	87	213	80	217.3	305.3
PRESSURE (PSIA)	350	350	342	342	60	35	17	17	0.7	0.7	17	15	14.7	16.3	72.5
H (MM BTU/HR)	-4083.4	-5177.2	-4957.8	-5329.6	-477.9	-5190.4	-286.1	-6639.6	-5129.8	-5980.4	-6702.9	-37	-722.6	-37.4	-0.8

STREAM	98	99	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	1993	3765	4705428	4705428	4705428	4705428	4705428	4705428	4705428	4705428
TEMPERATURE (F)	432.3	629.3	1117.5	839.9	690.3	595.5	463.5	343.6	333.9	259.9
PRESSURE (PSIA)	352	1910.5	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-12.9	-23.4	-1818.1	-2174	-2360.4	-2476.5	-2635.7	-2778.1	-2789.5	-2876.1

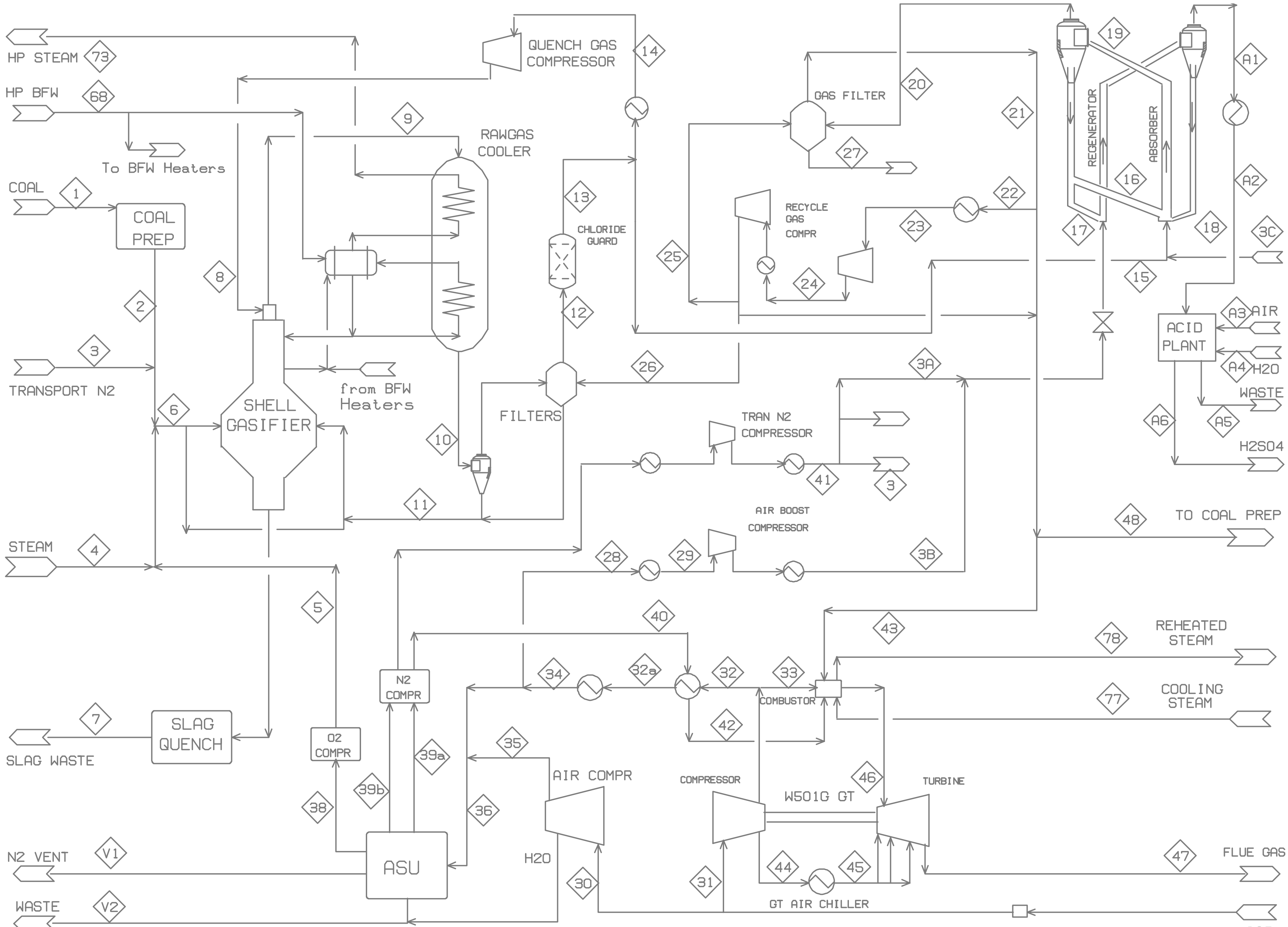


FIGURE 3A SHELL IGCC - (HGCU/W501G)

FIGURE 3B

SHELL IGCC HGCU - BASE CASE

SUMMARY :

POWER	MWe	EFFICIENCY:	%
GAS TURBINE	272.4	HHV	48
STEAM TURBINE	187.5	LHV	49.8
MISCELLANEOUS	35		
AUXILIARY (3%)	12.8		
PLANT TOTAL	412.2		

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
FLOW (LB/HR)	251336	235953	18043	6861	202778	464950	25445	198335	637840	637840	1272	640528	639791	198335	441456
TEMPERATURE (F)	59	59	104	693	204.7	159.1	300	199.4	1826.4	1004	1004	1000.3	996.8	174.4	996.8
PRESSURE (PSIA)	14.7	14.7	400	505	472	370	14.7	370	352.5	347.5	347.5	342.5	340	328	340
H (MM BTU/HR)	-925	-147.7	0.1	-37.8	5.1	-182.7	-59.2	-325	-664.1	-863.8	-2.5	-867.7	-867.8	-326.7	-598.8

STREAM	16	17	18	19	20	21	22	23	24	25	26	27	28	29	3A
FLOW (LB/HR)	4373249	485917	482761	5297720	438555	446337	13390	13390	13390	8034	4017	252	40999	40999	19748
TEMPERATURE (F)	1055	1055	1428.8	1063.7	1063.7	1052.3	1052.3	300	423.7	409	409	1052.3	190	120	105
PRESSURE (PSIA)	330	330	335	335	330	320	320	310	501.2	750	750	330	278	273	400
H (MM BTU/HR)	-15018	-1668.7	-1666.6	-17285.1	-608	-619.9	-18.6	-22.2	-21.6	-13	-6.5	-1	-0.5	-1.3	0.1

STREAM	3B	3C	V1	V2	30	31	32	32A	33	34	35	36	38	39A	39B
FLOW (LB/HR)	40999	252	168986	4873	426474	4320000	467473	467473	3311939	467473	424663	851137	202778	434535	41777
TEMPERATURE (F)	120	100	62	59	59	59	812.7	331.2	812.7	190	203.7	196.8	60	62	60
PRESSURE (PSIA)	345	340	91	15	14.6	14.6	282.2	280.2	282.2	278	278	278	92	91	265
H (MM BTU/HR)	-1.3	-1.1	-1.8	-33.3	-17.8	-180.3	68.1	11	482.3	-5.3	7	2.1	-0.9	-4.7	-0.3

STREAM	40	41	42	43	44	45	46	47	48	A1	A2	A5	A6	68	73
FLOW (LB/HR)	429500	46812	429500	431267	527109	527109	4172704	4699813	3018	63903	63903	61758	19265	385003	385003
TEMPERATURE (F)	192.4	105	712	1050.3	812.7	600	2583	1116.7	1050.3	1428.8	850	100	100	420	1050
PRESSURE (PSIA)	300	401.8	294	319	282.2	276.6	268.5	15.2	319	335	325	16	16	2116.9	1815
H (MM BTU/HR)	9.2	-0.1	66.2	-599.3	76.8	48	-89.5	-1793.7	-4.2	-5.3	-14.8	-1.2	-24.2	-2490.1	-2061.9

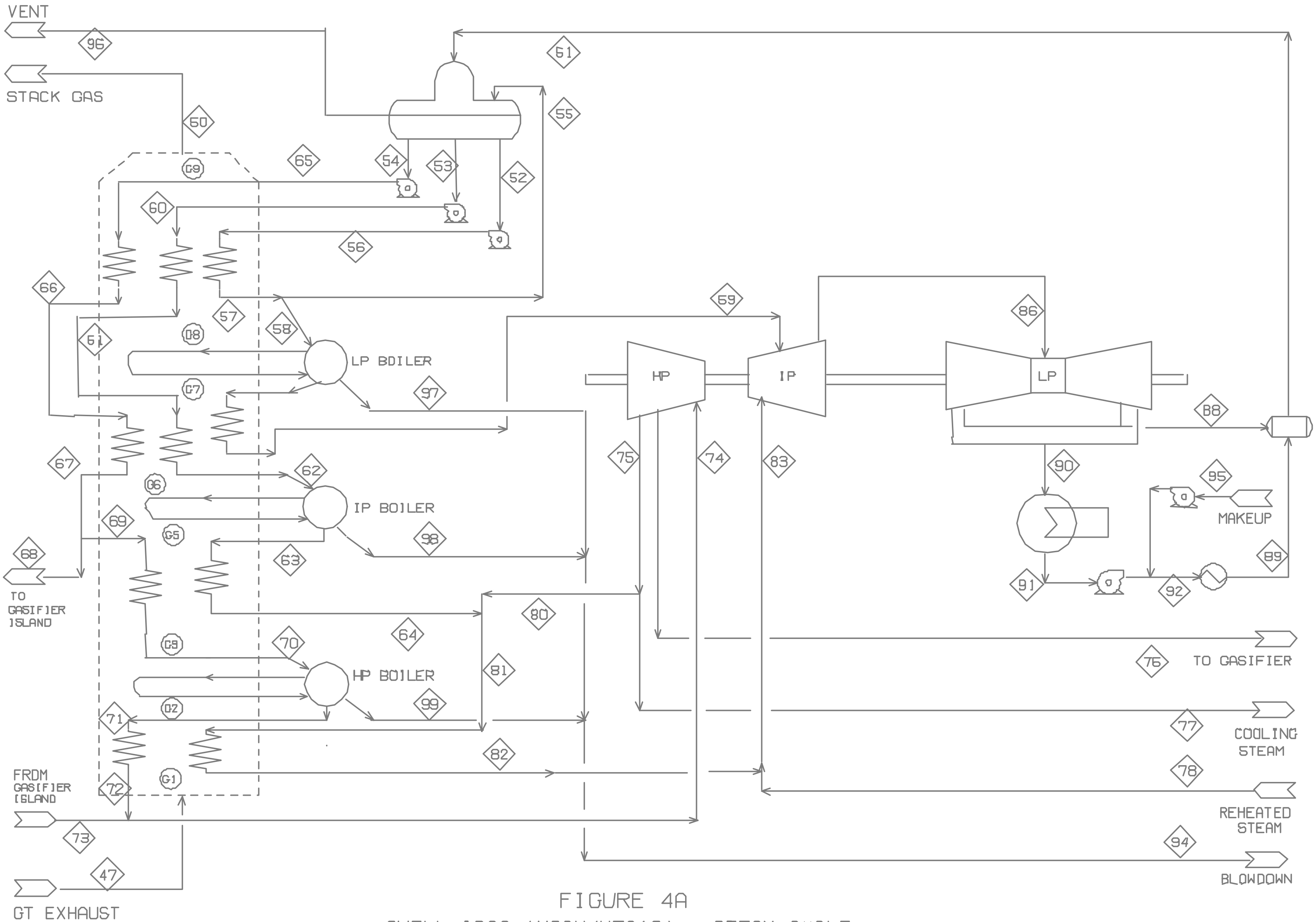


FIGURE 4A

SHELL IGCC (HGCU/W501G) - STEAM CYCLE

FIGURE 4B

Shell IGCC HGCU - Steam Cycle /HRSG Streams

STREAM	47	50	51	52	53	54	55	56	57	58	59	60	61	62
FLOW (LB/HR)	4699813	4699813	996579	275030	207684	770602	263036	275030	275030	11994	11874	207684	207684	207684
TEMPERATURE (F)	1116.7	259	205	217.3	217.3	217.3	286	217.4	286	286	420	218.1	286	420
PRESSURE (PSIA)	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	70.5	410.6	390	370.5
H (MM BTU/HR)	-1793.7	-2851.8	-6670.1	-1837.4	-1387.5	-5148.2	-1738.9	-1837.3	-1818.2	-79.3	-66.8	-1387.1	-1372.9	-1343.6

STREAM	63	64	65	66	67	68	69	70	71	72	73	74	75	76
FLOW (LB/HR)	205608	205608	770602	770602	770602	385003	385599	385599	381743	381743	385003	766746	759884	6861
TEMPERATURE (F)	432.3	620	221.1	286	420	420	420	620	629.3	1050	1050	1049.3	606.2	695.7
PRESSURE (PSIA)	352	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1910.5	1815	1815	1800	350	510
H (MM BTU/HR)	-1164.3	-1139.9	-5141.3	-5091.2	-4984	-2490.1	-2493.9	-2399	-2184.2	-2044.4	-2061.9	-4106.3	-4218.6	-37.8

STREAM	77	78	80	81	82	83	86	88	89	90	91	92	94	95
FLOW (LB/HR)	70000	70000	689884	895492	895492	965492	977365	61606	934973	915760	915760	934973	6053	19213
TEMPERATURE (F)	606.2	1055.4	606.2	609.4	1050	1050.4	485.1	352.8	136.2	88.8	87.9	87.7	213	80
PRESSURE (PSIA)	350	342	350	350	342	342	35	17	17	0.7	0.7	17	15	14.7
H (MM BTU/HR)	-388.6	-371.8	-3830	-4969.8	-4759.3	-5131.1	-5461.8	-348	-6322.1	-5349.4	-6236.4	-6367.4	-38.1	-131

STREAM	96	97	98	99	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	6298	120	2077	3856	4699813	4699813	4699813	4699813	4699813	4699813	4699813	4699813
TEMPERATURE (F)	217.3	305.3	432.3	629.3	1116.7	843.5	690.3	592.9	455.2	339.6	330.2	259
PRESSURE (PSIA)	16.3	72.5	352	1910.5	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-36	-0.8	-13.4	-23.9	-1793.7	-2144	-2334.9	-2454.2	-2620.2	-2757.3	-2768.3	-2851.8

1. Process Descriptions

Two IGCC Base Cases have been developed based on the Shell gasification process. The cases differ primarily in how the generated fuel syngas is cooled and in the gas cleanup sections. The Shell process uses an oxygen-blown, entrained flow, slagging gasifier. Both cases use a raw gas cooler (which is integrated with the gasifier and other heat exchangers) to generate high pressure superheated steam and a ceramic filter to remove particulates which are recycled to the gasifier. The syngas leaves the ceramic filter at 640°F for Case 1 and at 1004°F for Case 2. For Case 1, the fuel gas is further cooled and scrubbed before entering a cold gas cleanup unit (CGCU) using the MDEA/Claus/Scot process for sulfur removal and recovery. For Case 2, fuel gas enters a chloride guard bed which is followed by a hot gas cleanup unit (HGCU) using a transport absorber/regenerator process. The sulfur dioxide generated from the transport regenerator is sent to an acid plant for producing sulfuric acid. Power is recovered for both cases using a modified W501G gas turbine and a three pressure level reheat steam cycle.

The composition for the as-received Illinois #6 Coal used in the process is listed below. This coal is dried to approximately 5 % moisture in the coal prep section before being fed to the gasifier.

Proximate Analysis:	(Wt. %)	(Wt. %, dry)
Moisture	11.12	
Ash	9.70	10.91
Volatiles	34.99	39.37
Fixed Carbon	44.19	49.72
	100	100
HHV (Btu/lb)	11,666	13,126

Ultimate Analysis:	(Wt. %)	(Wt. %, dry)
Moisture	11.12	
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
	100	100

Additional features for the two cases are given in following sections. In Table 2, the processes used are compared.

Table 2 : Shell IGCC Base Cases Process Section Comparison

PROCESS SECTION	CASE 1	CASE 2
Shell Gasifier Exit Temp / Pres	1844°F / 352 psia	1826°F / 352 psia
Air Separation Plant Inlet Air Pres (psia): O2 / N2 Pres (psia):	50 % Integration GT 278 472 / 300	50 % Integration GT 278 472 / 300
Solid Waste **Particulates**	Slag Quench Filter, Scrubber	Slag Quench Ceramic Filter
Low Temp Gas Cooling/Heat Recovery	COS Hydrolysis, BFW Heating, Fuel Gas Reheating	N/A
Chloride/NH3 Removal	Water Treatment	Chloride Guard Bed
Sulfur Removal	CGCU-MDEA/CLAUS/SCOT (elemental sulfur)	HGCU – Transport Desulfuriztion, Acid Plant (sulfuric acid)
Clean Fuel Gas / Gas Addition	N2 Recycle from ASU	N2 Recycle from ASU
Gas Turbine - Power (MWe): - PR / TIT (F):	modified W501G 272 (target) 19.37 / 2583	same as Case 1
Steam Cycle - Turb Pres: HP/IP/LP - Superheat/Reheat - Exhaust LP Turb - HRSG Stack Temp	3 Pressure Level/Reheat 1800 / 342 / 35 (psia) 1050°F/ 1050°F 0.67 psia 260 °F	same as Case 1

1.1 Shell Gasifier

The gasifier is a dry-feed, pressurized, oxygen-blown, entrained-flow slagging type. The coal, (Illinois #6 for the cases considered), is pulverized and dried prior to being fed into the gasifier with a transport gas. Nitrogen is used as the transport gas in the cases considered. Coal, oxygen and steam enter the gasifier through horizontally opposed burners. Raw fuel gas is produced from high temperature gasification reactions and flows upwardly with some entrained particulates composed of ash and a small quantity of unreacted carbon. The high reactor temperature converts the remaining ash into a molten slag, which flows down the walls of the gasifier and passes into a slag quench bath. The reactor temperature is controlled by using part of the heat of reaction to generate high pressure steam in the membrane walls of the gasifier. The raw fuel gas is quenched at the reactor exit with cooled recycled fuel gas to lower the temperature below the melting point of the ash. This avoids sticky solids entering the raw gas cooler. The raw gas cooler further cools the gas and generates high-pressure steam which is sent to the steam cycle. Solids are recovered in the following particulate filter and recycled back to the reactor. Figures 1 and 3 illustrate the gasification section and major process streams relationship to other process sections. In Table 3, gasifier conditions are listed for the two Shell IGCC cases.

1.2 Air Separation Plant (ASU)

For both cases, an advanced high pressure cryogenic oxygen plant that takes advantage of the air (278 psia) extracted from the W501G gas turbine is employed. This advanced design is available due to recent improvements made to the conventional air separation technology which operates efficiently only to about an air supply pressure of 170 psia. The advanced ASU by operating at a higher pressure results in the oxygen and nitrogen products being available from the cold box at higher pressures than in a conventional ASU. This reduces costs for the further compression of these streams. For operational flexibility, (in startup and turndown), the present cases consider that the air is supplied, in equal amounts (50%), from a bleed from the gas turbine compressor exhaust and as air supplied directly using a boost compressor. The GT Compressor bleed air preheats a nitrogen recycle stream (98.9% purity) being sent to the gas turbine to assist in NOX control and to increase the flowrate through the gas turbine expander. The amount of nitrogen recycled is adjusted for each case to yield a net gas turbine power of approximately 272 MWe. The amount of nitrogen recycle is about 65% for both cases. Nitrogen is also provided for coal transport gas and for purging process equipment. For Case 2, nitrogen is also provided to moderate the temperature rise in the HGCU transport regenerator section. The oxygen stream (95% purity) is supplied to the Shell gasifier. Table 4 lists some of the key parameters for the ASU designs for the two cases.

Table 3. Shell IGCC Base Cases - Gasifier Conditions

	CASE 1 CGCU	**CASE 2 HGCU**
Coal Flowrate (tons/day)		
- to Prep Plant:	3171	3016
- to Gasifier:	2977	2831
Coal Moisture (wt. %)	11.12	
- to Prep Plant:	5.33	11.12
- to Gasifier:		5.33
Gasifier Exit Conditions		
- Pressure (psia):	352	352
- Temp (°F)		
- Before Quench	2500	2500
- After Quench	1844	1826
Flowrates (lb/hr)		
- Coal Feed:	248089	235953
- Oxidant:	213207	202778
- Steam:	7214	6861
- Transport Nitrogen:	18971	18043
- Recycle Quench Gas:	194116	198335
- Recycle Fines:	1408	1272
- Slag:	26747	25445
- Raw Fuel Gas:	654818	637840
Heating Value (Btu/Scf) (from gasifier)		
- LHV	276	279
- HHV	291	294

Table 4. Shell IGCC Base Cases - ASU Summary

	Case 1 CGCU	**Case 2 HGCU**
% Air from Gas Turbine	50%	50%
Air Inlet Pres (psia)	278	278
Total Air Flowrate (lb/hr)	894918	851137
Oxidant Stream		
- Flowrate (lb/hr):	213207	202778
- Purity (mole % O2):	95.0	95.0
- ASU Pres (psia):	92	92
- Boost Compr Pres (psia):	472	472
Nitrogen Stream		
- Flowrate (lb/hr):	678488	645298
- Purity (mole % N2):	98.9	98.9
- ASU Pres (psia):	91 & 265	91 & 265
- Recycled to GT %/ T (°F) / P (psia):	61.2 / 712 / 294	66.6 / 712 / 294
- % Transport N2:	2.8	2.8
- % To HGCU:	N/A	3.0
- % Miscellaneous:	1.4	1.4
- % Vented:	34.6	26.2
Power Requirements (MWe)		
- Air Compressor:	19.5	18.6
- O2 Boost Compressor:	5.1	4.8
- N2 Boost Compressors:	7.3	8.0

1.3 Gas Cooling Section - Case 1

For Case 1, the raw fuel gas from the particulate filter enters a gas cooling section which consists of several heat exchangers, catalytic hydrolyzer, and a water scrubber. The raw fuel gas is initially cooled to 450°F and sent to the hydrolyzer which converts the carbonyl sulfide (COS) to hydrogen sulfide. The gas stream is further cooled to 220°F before entering a water scrubber

which reduces the temperature to 100°F. Any hydrogen chloride and ammonia is assumed to be in the scrubber water discharge which is sent to a water treatment unit.
A portion of the cooled fuel gas stream, approximately 30%, is split off and recycled to quench the hot raw fuel gas stream exiting the gasifier. The remaining fuel gas, 70%, is sent to the CGCU section for sulfur removal.

The heat recovered in the heat exchanger network is used in reheating the cleaned fuel gas from the downstream CGCU process and for heating boiler feed water in the steam cycle.

1.4 Cold Gas Cleanup Unit (CGCU) - CASE 1

The MDEA/Claus/SCOT process is used for cold gas cleanup and sulfur recovery. Refer to Figure 1 for a conceptual idea of the equipment setup for each process. In the MDEA step, the cooled gas from the gas cooling section enters an absorber where it comes into contact with the MDEA solvent. As it moves through the absorber, almost all of the H_2S and a portion of the CO_2 are removed. The solute-rich MDEA solvent exits the absorber and is heated by the solute-lean solvent from the stripper in a heat exchanger before entering the stripping unit. Acid gases from the top of the stripper are sent to the Claus/SCOT unit for sulfur recovery. The lean MDEA solvent exits the bottom of the stripper and is cooled through several heat exchangers. It is then cleaned in a filtering unit and sent to a storage tank before the next cycle begins.

The Claus process is carried out in two stages. In the first stage, about one-quarter of the gases from the MDEA unit, which exits at 161°F, are mixed with the recycle acid gases from the SCOT unit and are burned in the first furnace. The remaining acid gases are added to the second-stage furnace, where the H_2S and SO_2 react in the presence of a catalyst to form elemental sulfur. The gas is cooled in a waste heat boiler and then sent through a series of reactors where more sulfur is formed. The sulfur is condensed and removed between each reactor. A tail gas stream containing unreacted sulfur, SO_2, H_2S, and COS is sent for further processing in the SCOT unit. This tail gas is heated before entering a reactor where SO_2 converts to H_2S with the aid of a cobalt-molybdate catalyst. The effluent is cooled by waste heat boilers and direct quench before being sent to an absorber column where the H_2S is removed. The H_2S rich stream is sent to the regenerator before being recycled to the absorber. The acid gas from the regenerator is recycled to the Claus step. Further information is provided in Table 5.

Table 5. Shell IGCC Base Cases - CGCU Conditions

	Case 1 CGCU
Sulfur Balance: (lb sulfur/hr)	
- MDEA Feed	6542.4
- Acidgas to Claus	6505.2
- Cleaned Fuel Gas	36.6
- Sulfur Product	6495.7
- SCOT Vent Gas	10.1
Key Conditions	
- PPMV to CGCU	9418
- PPMV Clean Fuel Gas	54
- Sulfur Recovery (weight %)	99.3
- Steam Requirements (lb/hr)	86350
- Power Requirements (KWe)	909.2

1.5 Chloride Guard Bed / Fine Particulate Removal - Case 2

For Case 2, the raw fuel gas exits the particulate removal filter (at 1004°F) and is sent to chloride guard bed section for hydrogen chloride removal. These guard beds containing commercial grade Nahcolite capture the chloride and any other halogens. The beds will require periodic treatment and operate with several on-line while others are being renewed. The resulting fuel gas stream is sent to the HGCU section for sulfur removal. A gas filter is used following the HGCU section to guard against any fine particulates left (or generated in HGCU) in the clean fuel gas sent to the gas turbine.

1.6 Transport Desulfurization HGCU - Case 2

The representation for this section was based on information provided by L. Bissett (NETL). NETL is currently developing an on-site (Morgantown) pilot plant to test this HGCU option for a number of sorbents. In the HGCU section, the transport absorber operates at an inlet pressure of 340 psia. A zinc based sorbent is used. The reaction occurs as a simple exchange between the ZnO portion of the sorbent and the sulfur. The cleaned fuel gas exits at 1064°F and enters a gas filter to capture any particulates before being sent to the gas turbine combustor. (A small portion of the cleaned filtered fuel gas is recycled and pressurized for use in the gas filter.)

The absorber consists of a riser reaction section, a solids/gas separation vessel, and a solids return dipleg. The riser operates at a high void fraction of approximately 95 percent. The large amount of sorbent recirculation results in only a small change in the sorbent sulfur content through this section. A slip stream of approximately 10 percent of the sorbent stream exiting the separation vessel is sent to a regenerator riser, while the remaining portion is combined with regenerated sorbent and sent back for the next absorber cycle. The regenerator is assumed to remove only a portion of the absorbed sulfur. This removal matches the sulfur that is removed from the raw fuel gas that enters the absorber. Since only a small amount of sulfur reacts, the regenerator exit temperature can be controlled to a value of approximately 1400 °F by adjusting the amounts of air (from GT) and nitrogen (from ASU) used. The regenerator waste gas stream is recycled to the sulfuric acid plant for SO_2 removal. HGCU conditions are listed in Table 6.

1.7 Sulfuric Acid Plant - Case 2

In the simulation model, no process details were used to represent the sulfuric acid plant. The only item taken into consideration was the acid plant power consumption rate of 46 watts per lb/hr SO_2 fed to the plant. The sulfuric acid production was based on closing the sulfur balance. However, the following process was used as a basis for the cost analysis.

The regeneration gas from the desulfurization section enters the sulfuric acid plant and passes over a vanadium catalyst stage at temperatures between 800 and 825°F. The temperature is allowed to increase adiabatically as the SO_2 is converted to SO_3. After the reaction is 60 to 70 percent complete, it is stopped. The gas stream is then cooled in a waste heat boiler and passed through subsequent stages of catalyst until the temperature of the gas passing through the last stage is below 800 °F. This process usually requires two to three stages of catalyst. Once cooled, the gas stream is sent to an intermediate absorber tower where some of the SO_3 is removed with 98 percent sulfuric acid. The gases leaving the absorber are reheated and passed over the remaining catalyst stages in a converter. The gases are again cooled and sent to a final absorber tower. Upon exiting the final absorber, the gases are vented to the atmosphere. The conversion of SO_2 to SO_3, and subsequently Sulfuric Acid, using this process is about 99.8 percent.

Table 6. Shell Gasifier IGCC Base Cases- HGCU Conditions

Sulfur Balance Information:	Flowrate (lb/hr)
Sulfur in Raw Fuel Gas	6299.58
Sulfur in Regenerator Waste	6299.07
Sulfur in Clean Fuel Gas	6.73
(ASPEN Convergence Error Sulfur %)	0.0989
PPMV of Sulfur in Raw Fuel Gas	9275
PPMV of Sulfur in Clean Fuel Gas	10 (Set in simulation)
HGCU Sulfur Capture Eff. (weight %)	99.89
Mole % SO_2 in Regenerator Waste	9.69
Regenerator Exit Gas Temp (°F)	1429
Regenerator Air Temp (°F)	120

HGCU Solids:	**Flowrate (1000 lb/hr)**	**Sorbent Utilization** *
To Absorber Rise	4856.01	.443
From Absorber Separator	4859.16	.450
To Regenerator Riser	485.92	.450
From Regenerator. Separator	482.76	.381

Ratio: Solids to Absorber/Solids to Regenerator = 9.99

* Sorbent utilization = moles of ZnS/total moles of ZnX compounds

1.8 Gas Turbine

Both cases were based on using a modified W501G gas turbine that was integrated with the Air Separation Unit (ASU). From the compressor exhaust, a bleed stream is used to supply 50% of the air supply needed for the ASU. An additional bleed, 14% of the compressor discharge air, is chilled to 600°F and used for cooling in the turbine expander. Heat recovered from the air cooler is used in the steam cycle. For Case 2, the compressor discharge also supplies air for use in the HGCU regenerator. The remainder of the compressor discharge air is used to combust the clean fuel gas. The ASU returns a nitrogen stream to the gas turbine combustor to assist in NOX control and to increase the flowrate and the power generated in the turbine expander. The nitrogen recycle flowrate is set by requiring that the gas turbine power generated equals approximately 272 MWe. Combustor duct cooling is accomplished using intermediate pressure steam supplied from the steam bottoming cycle. This reheated steam is returned to the steam cycle. The combustor exhaust gases enter the expander (2583°F, 269 psia), where energy is recovered to produce power.

The original turbine design specifications are based on a natural gas fuel rather than a coal derived syngas. The syngas□s significantly lower heating value when compared to natural gas requires a higher flow rate to obtain the desired turbine firing temperature. To allow for the higher flow rate, an increase in the first nozzle areas will be required. The original combustor will also be replaced with a modified design to handle the lower BTU syngas. In the cases considered, the syngas composition varies depending on the fuel processing prior to the gas turbine and the amount of nitrogen recycled from the ASU. In Table 7, the fuel gas composition for each case is listed both with and without the nitrogen stream addition. In Table 8, the gas turbine conditions are listed for the three Cases.

Table 7. Shell IGCC Base Cases - Fuel Gas Composition (Mole %)

	(No Nitrogen Recycle from ASU)		**(Nitrogen Recycle from ASU)**	
Shell Gas Cleaning	**CASE 1 CGCU**	**CASE 2 HGCU**	**CASE 1 CGCU**	**CASE 2 HGCU**
Mole %:				
O_2	-	-	0.25	0.26
N_2	4.32	4.23	43.5	44.3
Ar	0.92	0.88	0.70	0.67
H_2	29.7	28.8	17.4	16.6
CO	62.7	60.8	36.7	35.0
CO_2	2.06	2.32	1.22	1.36
H_2O	0.30	2.93	0.22	1.73
CH_4	0.04	0.04	0.02	0.02
H_2S	43 PPM	9.1 PPM	25 PPM	5.2 PPM
COS	12 PPM	0.9 PPM	6.8 PPM	0.5 PPM
NH_3	-	34 PPM	-	19 PPM
HCL	-	-	-	-
Heating Value (HHV) (Btu/Scf)	298	289	167	166

Table 8. Shell IGCC Base Cases - W501G Gas Turbine Conditions

Shell Gas Cleaning	CASE 1 CGCU	CASE 2 HGCU
Pressure (psia)		
- to Filter	14.7	* (Same as Case 1)
- Compressor inlet	14.57	*
- Compressor outlet	282	*
- Combustor exit	269	*
- Expander exhaust	15.2	*
Pressure Ratio	19.4	*
Flowrates (lb/hr)		
- Compr inlet Air	4,320,000	*
- Fuel Gas	432,075	431,267
- Nitrogen Recycle	415,244	429,500
- Bleed Air to ASU	448,410	426,474
- Bleed Air to HGCU	N/A	40,999
- Air Cooling Bleed	527,109	*
- Air Compr Leakage	13,478	*
- Steam Combustor Duct Cooling	70,000	*
- Expander Exhaust Gas to HRSG	4,705,428	4,699,813
Temperature (°F)		
- Inlet Air	59	*
- Compressor outlet	813	*
- Nitrogen Recycle	712	*
- Fuel Gas	600	1050
- Combustor exhaust	2613	2613
- Turbine inlet	2583	2583
- Turbine exhaust	1103	1117
Power (MWe)		
- Compressor	-237.1	-237.2
- Expander	513.3	513.5
- Generator Loss	-3.9	-3.9
- Net Gas Turbine	272.3	272.4

1.9 Steam Cycle

The steam cycle used for the two Cases is based on a design by D. Turek (ABB Power Plant Laboratories). Pressure drops and steam turbine isentropic efficiencies were based on information from a study by Bolland[1]. The cycle is a three-pressure level reheat process. Major components include a heat recovery steam generator (HRSG), steam turbines (high, intermediate, and low pressure), condenser, steam bleed for gas turbine cooling, recycle water heater, and deaerator. The differences are related to the heat integration possible with the gasifier island sections. These include:

- The raw fuel gas is cooled to 640°F for Case 1 but only to 1004°F for Case 2 in the raw gas cooler that follows the gasifier. This reduces the amount of high pressure steam generated in this exchanger.
- The above reduction is reduced somewhat due to Case 2 having two additional high quality heat sources in the heat exchanger prior to the acid plant and in the heat exchanger used to cool the recycled quench gas.
- Both cases have a number of heat exchangers that supply low quality heat for condensate reheating in the steam cycle. The overall available low quality heat is slightly larger for Case 1. The condensate from the steam condenser using low quality heat is reheated to 152°F for Case 1 and to 136°F for Case 2. A bleed of low quality steam (50648 lb/hr - Case 1, 261606 lb/hr - Case 2) is used to further heat condensate to 205°F.
- For Case 1, low pressure steam (60 psia, 600 psia) at a rate of 86350 lb/hr is sent to the CGCU section. This increases the makeup water requirements for Case 1 in the steam cycle.

In Figures 2 and 4 the steam cycle and process flows are provided for the two cases. The primary heat recovered is from the exhaust gas stream of the gas turbine and from the raw fuel gas exiting the gasifier to the raw gas cooler. Additionally, heat is integrated from the gas turbine cooling air chiller, from recycle gas coolers, and from several gasifier island gas coolers. Steam generation occurs at the three pressure levels of 72.5 psia, 353 psia, and 1911 psia in the HRSG. The cycle includes a parallel superheating/reheating section that raises the temperature to 1050°F for both the high pressure steam and for the combined intermediate pressure steam and high pressure turbine exhaust steam. Steam for the gas turbine combustor duct cooling is extracted from the HP turbine at a pressure of 350 psia. The return steam from the gas turbine combustor is combined with reheat steam and sent to the IP steam turbine. The LP steam turbine discharges at 89°F and 0.67 psia. The steam cycle conditions are summarized in Table 9.

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1 "A Comparative Evaluation of Advanced Combined Cycle Alternatives", Transactions of the ASME, April 1991.

Table 9. Shell IGCC Base Cases - Steam Cycle Conditions

HRSG Stack Gas Temperature:	260 °F
Deaerator Vent:	0.5% of inlet flowrate
LP,IP, and HP drum blowdown:	1.0% of inlet flowrate
Pressure drops:	5% of inlet (except IP superheater - 2 psia and line Drop before HP turbine - 15 psia)
High Pressure Turbine Inlet:	1800 psia / 1050 °F
Intermediate Pressure Turbine Inlet:	342 psia / 1050 °F
Low Pressure Turbine Inlet:	35 psia
Low Pressure Turbine Exhaust:	0.67 psia

Pressure Level	Steam Conditions		HRSG Approach Delta Temp (°F)	
	Pressure (psia)	Saturation Temp (°F)	CASE 1	CASE 2
Low	72.5	305	29	25
Intermediate	352	432	32	23
High	1911	629	61	61

Power Production (MWe)	CASE 1 CGCU	CASE 2 HGCU
Steam Turbines	191.7	190.4
Generator Loss	-2.9	-2.9
Net Steam Turbines	188.8	187.5
Pump	-2.3	-2.2

1.10 Power Production

An auxiliary power consumption is assumed as 3 percent of the total power production by the Gas Turbine and the Steam Turbines minus the power consumed by the miscellaneous pumps, expanders, compressors, and blowers. The power production and the overall process efficiency are listed in Table 10 for the two Shell IGCC cases.

Table 10. Shell IGCC Base Cases - Power Production

	CASE 1 CGCU	**CASE 2 HGCU**
Gas Turbine (Mwe)	272.3	272.4
Steam Turbine (Mwe)	188.8	187.5
Miscellaneous (Mwe)	-35.5	-35.0
Auxiliary (Mwe)	-12.8	-12.7
Plant Total (Mwe)	412.8	412.2
Overall Process Efficiency (HHV, %):	45.7	48.0
Overall Process Efficiency (LHV, %):	47.4	49.8

2. Simulation Development

The Shell IGCC gasification section was developed based on information available in several reports by Shell and using information available from EPRI reports. Specifically, the references included:

- Shell Reports:
  - Shell's SCGP-1 Test Program - Final Overall Results. U.Mahagaokar, J. N. Phillips, A.B. Krewinghaus, Tenth EPRI Conference on Coal Gasification, (1991).
  - Cost Improvements in Shell CGCU 1991 Design. C.A. Bayans & G. A. Cremer, Tenth EPRI Conference on Coal Gasification, (1991).
  - Improvements in SCGP since DEMKOLEC. E. L. Doering, Shell Oil Company Report, (1991).
  - Single Train IGCC of 400 Mwe and 46%+ Efficiency. Prepared by staff from Shell Internationale Petroleum. (1996).
- EPRI Reports:
  - GS-6283 (1989), GS-6493 (1989).

The models for the gas turbine (W501G) and the steam cycle were based on previously developed ASPEN simulations. The remaining process sections (i.e. HGCU, CGCU, ASU, Acid Plant) were based on representations available in a number of earlier studies. A search of the ASPEN Archive CMS Library will provide example cases for these process sections.

The ASPEN PLUS (version 10.1) simulation codes are stored in the EG&G's Process Engineering Team Library.

3. Cost of Electricity Analysis

The cost of electricity for the Shell cases was performed using data from the EG&G Cost Estimating notebook and several contractor reports. The format follows the guidelines set by EPRI TAG. Details of the individual section costs are described below and are based on capacity-factored techniques. The COE spreadsheets are included in Appendix A. All costs are reported in 1st Quarter 1999 dollars.

3.1 Coal Preparation

The coal preparation section includes costs for the receiving, conveying, drying and pulverizing systems. The coal flow rate in the Shell HGCU case is 3016 tons per day (Illinois #6 coal), resulting in a section cost of $17.2 million. The coal flow rate for the Shell CGCU case is 3171 tons per day, resulting in a cost of $17.8 million.

3.2 Oxygen Plant

The cost for the oxygen plant includes the air separation unit, the air precoolers, the oxygen compressors, the nitrogen compressors and the air compressors. Both systems use a high-pressure air separation unit. The oxygen plant for Case 2 produces 2433 tons per day oxygen with a cost of $49.6 million. The oxygen plant for Case 1 produces 2558 tons per day oxygen with a cost of $51.2 million.

3.3 Shell Gasifier

The cost for the gasification section includes the gasifier, the raw gas cooler, slag handling and particulate removal. The cases are based on one gasification train with a nominal capacity of 3000 tons per day. The Shell CGCU cost of $78.4 million was derived from a similar Shell system in a previous report[2]. The Shell HGCU differs in the raw gas cooler section where the gas is cooled to 1004°F instead of 640°F. According to the reference, the cooler was approximately 25% of the total gasification cost. The HGCU gasification section cost, $72.3 million, was obtained from scaling the corresponding CGCU sections. A process contingency of 5 percent was added to the total plant cost based on the development of the gasifier.

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2 "Shell-Based Gasification- Combined Cycle Power Plant Evaluations," Final Report, Electric Power Research Institute AP-3129, Prepared by Flour Engineers Inc., June 1983.

3.4 Low Temperature Gas Cooling and COS Hydrolysis (Cold Gas case only)

The cost for the low temperature cooling and gas saturation section includes several heat exchangers, separators, and the hydrolyzer. The cost for the CGCU case is $9.4 million.

3.5 MDEA/ Claus/ SCOT Section (Cold Gas cases only)

The cost of the MDEA acid gas removal system includes the absorber column, the stripping column, heat exchanger and pumps. The cost for the Shell CGCU case is $5.1 million.

The cost for the Claus/SCOT sulfur recovery and tail gas treating units for the Shell CGCU case is based on 85 tons per day of sulfur entering the unit. The total cost for both units is $14.2 million.

3.6 Gas Conditioning (Hot Gas case only)

The gas conditioning section includes a cyclone, two gas filters, and chloride guard. The cost for the Shell HGCU is $15.2 million and is based on one process trains. A process contingency of 10% was added to the total plant cost based on the development of the gas conditioning components.

3.7 Desulfurization Section (Hot Gas case only)

The cost for the transport desulfurization section was derived from a previous report[3]. This includes costs for sorbent hoppers, transport desulfurizer and cyclones. However, the previous report was for a polishing unit and it is unclear how no sulfur capture in the gasifier will affect the price of the unit or the amount of sorbent needed. The amount of sorbent used was based information from the Separations and Gasification Engineering Division of NETL. The cost for the Shell HGCU is $7.3 million and is based on one process trains. A process contingency of 15% was added to the total plant cost based on the development of the desulfurization sections.

3.8 Acid Plant Section (Hot Gas case only)

The cost for the sulfuric acid plant is based on a Monsanto contact process. The unit produces 231 tons per day of sulfuric acid and costs $18.4 million.

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3 "Advanced Technology Repowering," Final Report, Prepared for the U.S. Department of Energy, Morgantown Energy Technology Center, Prepared by Parsons Power Group, Inc. May 1997

3.9 Gas Turbine Section

The cost for the W501G gas turbine was derived from the Gas Turbine World 96 Handbook[4]. The cost from the handbook was $185/kW and included all the basic turbine components. A factor of 7% was added for modifications and installation. The gas turbine powers of 272.4 Mw_e and 272.3 MW_e, for the Shell HGCU and CGCU, respectively, resulted in an approximate cost of $54 million. A process contingency of 5% was added to the total plant cost based on the development of the modified gas turbines.

3.10 HRSG/ Steam Turbine Section

The cost for the steam cycle is based on a three-pressure level steam cycle. The Shell HGCU steam turbine power is 187.5 MW_e, with a combined section cost of $50.4 million. The Shell CGCU steam turbine power is 188.8 MW_e, with a combined section cost of $50.7 million.

3.11 Bulk Plant Items

Bulk plant items include water systems, civil/structural/architectural, piping, control and instrumentation, and electrical systems. These were calculated based on a percentage of the total installed equipment costs. The percentages in parenthesis are for the hot-gas cleanup process, which has a lower water requirement, and therefore, a smaller percentage for piping and water systems. The following percentages were used in this report.

Bulk Plant Item	% of Installed Equipment Cost
Water Systems	7.1 (5.1)
Civil/Structural/Architectural	9.2
Piping	7.1 (5.1)
Control and Instrumentation	2.6
Electrical Systems	8.0
Total	34.0 (30.0)

Table 11, Table 12, and Table 13 show the assumptions used in this COE analysis. The total capital requirement for the Shell HGCU case is $564,963,000 or $1370/kW, compared to $566,101,000 or $1371/kW for the Shell CGCU case. The levelized cost of electricity for the HGCU case in constant dollars is 40.7 mills/kWh, compared to 42.1 mills/kWh for the CGCU case.

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4 Gas Turbine World Performance Specifications, annual issue, Pequot Publishing Inc., Fairfield Connecticut.

Table 11. Capital Cost Assumptions

Engineering Fee	10% of PPC*
Project Contingency	15% of PPC
Construction Period	4 Yrs
Inflation Rate	3%
Discount Rate	11.2%
Prepaid Royalties	0.5% of PPC
Catalyst and Chemical Inventory	30 Dys
Spare Parts	0.5% of TPC**
Land	200 Acres @ $6,500/Acre
Start-Up Costs	
Plant Modifications	2% of TPI***
Operating Costs	30 Dys
Fuel Costs	7.5 Dys
Working Capital	
Coal	60 Dys
By-Product Inventory	30 Dys
O&M Costs	30 Dys

* PPC = Process Plant Cost
** TPC = Total Plant Cost
*** TPI = Total Plant Investment

Table 12. Operating & Maintenance Assumptions

<u>Consumable Material Prices</u>	
Illinois #6 Coal	\$29.40/Ton
Raw Water	\$0.19 /Ton
MDEA Solvent	\$1.45/Lb
Claus Catalyst	\$470/Ton
SCOT Activated Alumina	\$0.067/Lb
Sorbent	\$6,000/Ton
Nahcolite	\$275/Ton
Off-Site Ash/Sorbent Disposal Costs	\$8.00/Ton
Operating Royalties	1% of Fuel Cost
Operator Labor	\$34.00/hour
Number of Shifts for Continuous Operation	4.2
Supervision and Clerical Labor	30% of O&M Labor
Maintenance Costs	2.2% of TPC
Insurance and Local Taxes	2% of TPC
Miscellaneous Operating Costs	10% of O&M Labor
Capacity Factor	85%

Table 13. Investment Factor Economic Assumptions

Annual Inflation Rate			3%
Real Escalation Rate (over inflation)			
O&M 0%			
Coal			-1.1%
Discount Rate			11.2%
Debt	80% of Total	9.0% Cost	7.2% Return
Preferred Stock	0% of Total	0.0% Cost	0% Return
Common Stock	20% of Total	20.0% Cost	<u>4.0% Return</u>
			11.2% Total
Book Life			20 Yrs
Tax Life			20 Yrs
State and Federal Tax Rate			38%
Investment Tax Credit			0%
Number of Years Levelized Cost			10 Yrs

Appendix A

COE Spreadsheets

Shell CGCU IGCC Case CASE 1 413 MW POWER PLANT

1st Q 1999 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation	0	$0	$17,826
12	Oxygen Plant	0	$0	$51,204
12	Shell Gasifier	5	$3,922	$78,449
12	Quench Gas Compressor	5	$95	$1,900
14	Low Temperature Gas Cooling/Gas Saturation	0	$0	$9,353
14	MDEA	0	$0	$5,090
14	Claus	0	$0	$9,964
14	SCOT	0	$0	$4,214
15	Gas Turbine System	5	$2,702	$54,036
15	HRSG/Steam Turbine	0	$0	$50,671
18	Water Systems	0	$0	$20,072
30	Civil/Structural/Architectural	0	$0	$26,009
40	Piping	0	$0	$20,072
50	Control/ Instrumentation	0	$0	$7,350
60	Electrical	0	$0	$22,617

Subtotal, Process Plant Cost		$378,829
Engineering Fees		$37,883
Process Contingency (Using cont. listed)	$6,719	
Project Contingency, 15 % Proc Plt & Gen Plt Fac		$56,824
Total Plant Cost (TPC)		$480,255
Plant Construction Period, 4.0 Years (1 or more)		
Construction Interest Rate, 11.2 %		
Adjustment for Interest and Inflation		$60,286
Total Plant Investment (TPI)		$540,541
Prepaid Royalties		$1,894
Initial Catalyst and Chemical Inventory		$61
Startup Costs		$13,156
Spare Parts		$2,401
Working Capital	$6,747	
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$566,101
$/kW		1371

ANNUAL OPERATING COSTS – CASE 1

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,171	T/D	$29.40	/T	$28,922
Consumable Materials					
Water	1,263	T/D	$0.19	/T	$74
MDEA Solvent	403.2	Lb/D	$1.45	/Lb	$181
Claus Catalyst	0.01	T/D	$470	/T	$1
SCOT Activated Alumina	15.9	Lb/D	$0.67	/Lb	$3
SCOT Cobalt Catalyst					$5
SCOT Chemicals					$16
Ash/Sorbent Disposal Costs	321	T/D	$8.00	/T	$797
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,604
Maintenance Costs	2.2%				$10,566
Royalties					$289
Other Operating Costs					$868
	Total Operating Costs				$48,783
By-Product Credits					
Sulfur	78.0	T/D	$75.00	/T	$1,814
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
	Total By-Product Credits				$1,814
	Net Operating Costs				$46,969

BASES AND ASSUMPTIONS – CASE 1

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	32212	T	$0.19	/T	$6
MDEA Solvent	10282	Lb	$1.45	/Lb	$15
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alumina	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$61

Startup costs			
Plant modifications,	2	% TPI	$10,811
Operating costs			$1,646
Fuel			$699
		Total Startup Costs	$13,156
Working capital			
Fuel & Consumables inv	60	days supply	$5,644
By-Product inventory	30	days supply	$175
Direct expenses	30	days	$928
		Total Working Capital	$6,747

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	ACRS	
Investment Tax Credit	0.0	%

Financial structure

	% of	Current Dollar		Constant Dollar	
Type of Security	Total	Cost, %	Ret, %	Cost, %	Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY – CASE 1

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	33.0	27.3
Fuel Costs	10.3	8.9
Consumables	0.4	0.4
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-0.7	-0.6
Total Cost of Electricity	50.0	42.1

Shell HGCU IGCC Case CASE 2 — 412 MW POWER PLANT, 1st Q 1999 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation	0	$0	$17,221
12	Oxygen Plant	0	$0	$49,565
12	Shell Gasifier	5	$3,616	$72,313
12	Gas Compression (Recycle and Quench)	5	$200	$4,006
14	Gas Conditioning	10	$1,524	$15,245
14	Air Boost Compressor	0	$0	$660
14	Transport Desulfurizer	15	$1,101	$7,339
14	Sulfuric Acid Plant	0	$0	$18,440
15	Gas Turbine System	5	$2,704	$54,076
15	HRSG/Steam Turbine	0	$0	$50,357
18	Water Systems	0	$0	$14,750
30	Civil/Structural/Architectural	0	$0	$26,608
40	Piping	0	$0	$14,750
50	Control/ Instrumentation	0	$0	$7,520
60	Electrical	0	$0	$23,138

		Subtotal, Process Plant Cost		$375,988
Engineering Fees				$37,599
Process Contingency (Using cont. listed)			$9,145	
Project Contingency,	15	% Proc Plt & Gen Plt Fac		$56,398
		Total Plant Cost (TPC)		$479,130
Plant Construction Period,	4.0	Years (1 or more)		
Construction Interest Rate,	11.2	%		
Adjustment for Interest and Inflation				$60,145
		Total Plant Investment (TPI)		$539,275
Prepaid Royalties				$1,880
Initial Catalyst and Chemical Inventory				$209
Startup Costs				$13,104
Spare Parts				$2,396
Working Capital			$6,800	
Land, 200 Acres				$1,300
		Total Capital Requirement (TCR)		$564,963
		$/kW		1370

ANNUAL OPERATING COSTS – CASE 2

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,018	T/D	$29.40	/T	$27,529
Consumable Materials					
Water	271	T/D	$0.19	/T	$16
HGCU Sorbent	0.07	T/D	$6,000	/T	$133
Nahcolite	3.0	T/D	$275	/T	$256
Ash/Sorbent Disposal Costs	306	T/D	$8.00	/T	$758
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,602
Maintenance Costs	2.2%				$10,541
Royalties					$275
Other Operating Costs					$867
	Total Operating Costs				$47,433
By-Product Credits					
Sulfuric Acid	230.9	T/D	$68.00	/T	$4,871
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
	Total By-Product Credits				$4,871
	Net Operating Costs				$42,562

BASES AND ASSUMPTIONS – CASE 2

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	6923	T	$0.19	/T	$1
HGCU Sorbent	31	T	$6,000	/T	$186
Nahcolite	77	T	$275	/T	$21
Total Catalyst and Chemical Inventory					$209

			COST, K$
Startup costs			
Plant modifications,		2 % TPI	$10,786
Operating costs			$1,653
Fuel			$665
		Total Startup Costs	$13,104
Working capital			
Fuel & Consumables inv	60	days supply	$5,402
By-Product inventory	30	days supply	$471
Direct expenses	30	days	$927
		Total Working Capital	$6,800

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY – CASE 2

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000
Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	32.9	27.3
Fuel Costs	9.8	8.5
Consumables	0.4	0.4
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-1.8	-1.6
Total Cost of Electricity	48.4	40.7

Appendix B

Modifications made to 1998 IGCC Process System Study

Modifications made to the 1998 IGCC Process System Study

The attached summaries show the results obtained previously for the 1998 IGCC Process System Study and the results obtained based on the changes listed below to the economic analysis and the process simulations.

Economics

The following changes were made to the economic section of the 1998 System Study cases done by EG&G for the Gasification Technologies Product Team.

- The costs were brought to 1st Quarter 1999 dollars.
- The contingencies for several sections were changed to reflect advancements in technology development.
- The operating and maintenance costs were lowered to reflect recent technology improvements and competitive pressure (Annual Energy Outlook 2000).
  The number of operators was lowered.
  The maintenance costs were lowered. This is based on a percentage of the Total Plant cost.
- The cost for the Air Separation Units were updated to reflect recent price quotes from a supply vendor.
- The cost and attrition rate for the sorbent in the Hot Gas Cleanup cases were updated to reflect improvements in the state of the art sorbent development. The Separations and Gasification Engineering Division of NETL provided this information.
- The escalation rate of coal was updated to –1.1% from –0.9% and the price of coal was updated to $29.40/ton from $30.60/ ton per the Annual Energy Outlook 2000 projections.
- Some equipment costs were updated after viewing recent publications and talking to technical experts at NETL.

Process Simulations

The following changes were made to the process simulation section of the 1998 System Study done by EG&G for the Gasification Technologies Product Team.

- For Oxygen-blown gasifiers, the Air Separation Unit (ASU) uses an advanced cryogenic plant designed to take advantage of air being provided from a high pressure gas turbine. This resulted in the nitrogen and oxygen streams from the ASU being sent to boost compressors at higher pressures. This reduces power requirements for these compressors.
- Process Efficiencies for boost compressors and air compressors were based on industry recommended values. This resulted in isentropic stage efficiencies for air and nitrogen compressors of 83% compared with 85-87% being used in the 1998 study. Additionally, the oxygen boost compressor stage efficiency was set at 74% compared to 85% used previously. These modifications increased power requirements and partially eliminated the advantage (for oxygen-blown systems) of the above change.
- Simulation Codes are all available for use in ASPEN PLUS Version 10.1. (Some of the 1998 cases were in version 9.3).
- The databank for pure component information was changed to “Pure10” which is ASPEN

PLUS latest release. Only minor changes in some stream information resulted from this change.

- The ASPEN representation for boost compressors and the air compressor was changed from a series of compressor + intercoolers (ASPEN Blocks "COMPR" and "HEATX") to a multi-stage intercooled compressor (ASPEN Block "MCOMPR"). The low quality heat available from intercoolers was not used in the steam cycle. This had a minimal effect since most cases have excess low quality heat available.

FY 2000 IGCC Systems Summary Update

* (Contingencies on Hot Gas Cleanup Sections: Gas Conditioning 15/10%, Transport Desulfurizer 15%, Sulfator 15%)

	Texaco	Texaco		Shell		Destec		British Gas/	
	Quench	Radiant + Convective						Lurgi	
	CGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU
	CASE 1	CASE 2	CASE 3	CASE 1	CASE 2	CASE 1	CASE 2	CASE 1	CASE 2
Gas Turbine Power (MWe)	272.7	272.4	272.1	272.3	272.5	272.8	272.6	272.6	272.5
Steam Turbine Power (MWe)	152.3	191.7	183.8	188.9	187.6	172.2	171.1	133.4	130.3
Misc. /Aux. Power (MWe)	42.0	51.3	46.3	48.3	47.8	44.4	43.3	31.1	30.7
Total Plant Power (MWe)	382.9	412.8	409.6	412.8	412.4	400.6	400.4	374.9	372.1
Efficiency, HHV (%)	39.7	43.5	46.5	45.7	48.0	45.0	47.6	45.3	49.4
Efficiency, LHV (%)	41.2	45.1	48.3	47.4	49.8	46.7	49.4	47.0	51.3
Total Cap Requirement ($1000)	$500,599	$594,053	$561,229	$566,101	$564,963	$546,993	$538,933	$533,664	$503,640
$/kW	$1,307	$1,439	$1,370	$1,371	$1,370	$1,365	$1,346	$1,423	$1,354
Net Operating Costs ($1000)	$48,411	$49,422	$43,426	$46,969	$42,562	$46,487	$41,888	$46,445	$40,416
COE (mills/kW-H)	42.5	44.3	41.1	42.1	40.7	42.3	40.4	44.5	41.1

	KRW Air-Blown			KRW		Transport		Transport	
	With	/out In-Bed Sulf Captur		Oxygen Blown		Air-Blown		Oxygen-Blown	
	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU
	CASE 1	CASE 2	CASE 3				CASE 1		CASE 2
Gas Turbine Power (MWe)	272.6	272.4	272.8				272.8		272.6
Steam Turbine Power (MWe)	184.8	177.0	174.3				162.6		142.4
Misc. /Aux. Power (MWe)	24.5	25.3	25.5				20.0		31.3
Total Plant Power (MWe)	432.9	424.1	421.6				415.4		383.7
Efficiency, HHV (%)	48.4	44.3	46.3				49.8		47.1
Efficiency, LHV (%)	50.2	45.9	48.0				51.7		48.8
Total Cap Requirement (x1000)	$566,641	$544,961	$550,305				$484,062		$496,722
$/kW	$1,309	$1,285	$1,305				$1,165		$1,295
Net Operating Costs (x1000)	$54,059	$48,032	$43,740				$45,388		$47,294
COE (mills/kW-H)	42.4	40.3	39.5				38.1		41.9

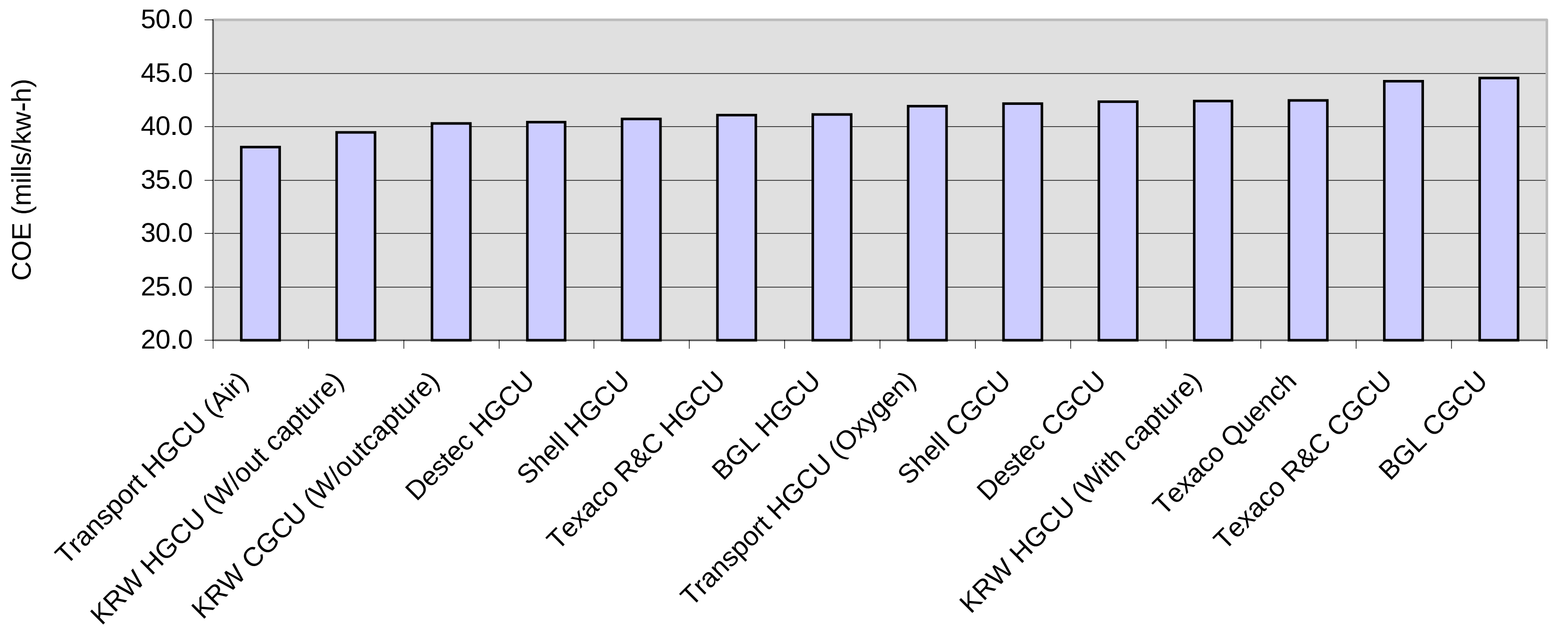
FY 1998 IGCC Systems Summary

	Texaco	Texaco		Shell		Destec		British Gas/	
	Quench	Radiant + Convective						Lurgi	
	CGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU
	CASE 1	CASE 2	CASE 3	CASE 1	CASE 2	CASE 1	CASE 2	CASE 1	CASE 2
Gas Turbine Power (MWe)	271.9	272.5	271.2	273.0	271.6	273.0	271.1	272.4	272.1
Steam Turbine Power (MWe)	154.1	192.4	184.9	188.3	189.2	173.5	172.0	131.2	130.7
Misc. /Aux. Power (MWe)	44.4	54.5	49.2	54.3	53.1	48.1	46.3	34.0	33.4
Total Plant Power (MWe)	381.7	410.4	406.9	407.1	407.7	398.5	396.9	369.5	369.3
Efficiency, HHV (%)	39.6	43.4	46.3	45.4	47.5	44.8	47.4	45.4	49.1
Efficiency, LHV (%)	41.1	45.0	48.1	47.0	49.3	46.5	49.1	47.1	50.9
Total Cap Requirement ($1000)	519,625	596,034	593,781	596,811	588,502	551,179	552,513	559,717	528,069
$/KW	1,361	1,452	1,459	1,466	1,443	1,383	1,392	1,515	1,430
Net Operating Costs ($1000)	67,128	69,832	70,836	67,876	69,445	65,711	67,279	65,889	64,710
COE (mills/KW-H)	47.2	48.1	48.8	47.9	48.0	46.2	47.0	50.3	48.5

	KRW Air-Blown			KRW		Transport		Transport	
	With	/out In-Bed Sulf Captur		Oxygen Blown		Air-Blown		Oxygen-Blown	
	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU
	CASE 1	CASE 2	CASE 3				CASE 1		CASE 2
Gas Turbine Power (MWe)	271.8	271.7	272.9				271.4		272.1
Steam Turbine Power (MWe)	181.0	172.7	170.8				160.1		141.9
Misc. /Aux. Power (MWe)	23.8	24.5	24.7				19.5		32.7
Total Plant Power (MWe)	429.0	419.9	419.1				412.0		381.3
Efficiency, HHV (%)	48.4	44.2	46.3				49.9		46.9
Efficiency, LHV (%)	50.2	45.8	48.0				51.7		48.7
Total Cap Requirement ($1000)	607,771	582,832	601,760				520,051		538,369
$/KW	1,417	1,388	1,436				1,262		1,412
Net Operating Costs ($1000)	75,562	68,706	71,722				64,417		67,551
COE (mills/KW-H)	48.3	46.1	48.0				43.6		48.4

COE Summary IGCC Systems Study 2000 Update		COE Summary IGCC Systems Study 1998	
Transport HGCU (Air)	38.1	Transport HGCU (Air)	43.6
KRW HGCU (W/out capture)	39.5	KRW CGCU (W/outcapture)	46.1
KRW CGCU (W/outcapture)	40.3	Destec CGCU	46.2
Destec HGCU	40.4	Destec HGCU	47.0
Shell HGCU	40.7	Texaco Quench	47.2
Texaco R&C HGCU	41.1	Shell CGCU	47.9
BGL HGCU	41.1	KRW HGCU (W/out capture)	48.0
Transport HGCU (Oxygen)	41.9	Shell HGCU	48.0
Shell CGCU	42.1	Texaco R&C CGCU	48.1
Destec CGCU	42.3	KRW HGCU (With capture)	48.3
KRW HGCU (With capture)	42.4	Transport HGCU (Oxygen)	48.4
Texaco Quench	42.5	BGL HGCU	48.5
Texaco R&C CGCU	44.3	Texaco R&C HGCU	48.8
BGL CGCU	44.5	BGL CGCU	50.3

IGCC Base Case COE Comparison



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