Process Engineering Division

Texaco Gasifier IGCC Base Cases

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PREFACE

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

EXECUTIVE SUMMARY

TEXACO GASIFIER IGCC BASE CASES

EXECUTIVE SUMMARY

ASPEN PLUS(version 10.1) Simulation Models and the Cost of Electricity (COE) have been developed for three IGCC cases based on the Texaco 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 Texaco 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 Slurry Prep - based on Illinois #6 coal, 66.5% solids.
- Texaco Gasifier - 240 Btu/Scf (HHV) syngas.
- Air Separation Unit (ASU) - high pressure process integrated with the gas turbine.
- "G" gas turbine -W501 G modified for coal derived fuel gas.
- Three pressure level subcritical reheat Steam Cycle
  - (1800 psia/1050 °F /342 psia/1050 °F /35 psia).

The gasifier and the gas cleanup systems account for the major differences between the three cases. Case 1 is based on the Texaco Gasifier / Quench design and cold gas cleanup (CGCU) for sulfur removal. The other two cases use the Texaco Gasifier / Radiant Syngas Cooler (RSC) / Convective Syngas Cooler (CSC) design. For sulfur removal, Case 2 uses cold gas cleanup (CGCU) and Case 3 uses transport desulfurization hot gas cleanup (HGCU). The RSC sections are used for generating high pressure saturated steam. The CSC section for Case 2 cools the raw (dirty) fuel gas to 400 °F with the recovered energy used for both steam generation and reheating clean fuel gas. For Case 3, the CSC section is used for steam generation with the raw (dirty) fuel gas cooled to 1004 °F.

The difference in gasifier pressure (615 psia for Quench design, 475 psia for RSC design) results in the Gas Cooling/Heat Recovery (GCHR) sections for the CGCU cases having different energy recovery schemes for the available low quality heat from water condensation. Case 1 (higher pressure) recovers heat for ammonia strip steam, for boiler feedwater heating, and for low-pressure steam generation. Additionally, this case uses the high-pressure condensate for saturating the clean fuel gas. For Case 2 the energy recovery occurs at lower temperatures and is used for ammonia strip steam and boiler feedwater heating. The low-pressure steam generation for the steam cycle and condensate use for fuel gas saturation is not feasible for Case 2. Case 3 uses HGCU and the water in the raw fuel gas from the gasifier is not condensed out in a GCHR section. This reduces the dirty water treatment sections and reduces the amount of nitrogen recycled from the ASU to the gas turbine combustor. Other differences will be outlined in the report sections for the three cases.

Process flow diagrams and material and energy balances summaries are shown in Figures 1-6 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 the three cases. The lowest efficiency and the best COE is for Case 1. Steam generation (and steam power production) is reduced due to a lack of radiant and convective syngas cooler sections and this primarily contributes to the efficiency decrease. However, the lowest (best) COE is also primarily due to the Texaco Gasifier/Quench design not having these expensive heat recovery sections and also to the resulting smaller steam cycle. For the Texaco Gasifier/RSC/CSC designs, Case 3 using HGCU has an advantage in overall process efficiency of nearly three percentage points compared to Case 2 which uses CGCU. The higher average fuel gas temperature to the gas turbine reduces the amount of coal used. The higher moisture content in the fuel gas requires a smaller nitrogen recycle from the ASU section to fully load the gas turbine to produce approximately 272 MWe. These factors mainly contribute to the higher efficiency. Case 3 (HGCU) and Case 2 (CGCU) have nearly the same COE despite the process efficiency difference of nearly three percentage points. The COE estimate report section discusses the various differences in capital cost, coal cost, by-product credits, chemical costs, and sorbent costs for these two cases to clarify this result.

Table 1 : Texaco Gasifier IGCC Base Cases Summary

	CASE 1	**CASE 2**	**CASE 3**
Cooling Mode	Quench	RSC+CSC	RSC+CSC
Sulfur Removal	CGCU	CGCU	HGCU
Gas Turbine Power (MWe)	272.7	272.4	272.1
Steam Turbine Power (MWe)	152.3	191.7	183.8
Misc./Aux. Power (MWe)	42.0	51.3	46.3
Total Plant Power (MWe)	382.9	412.8	409.6
Efficiency, HHV (%)	39.7	43.5	46.5
Efficiency, LHV (%)	41.2	45.1	48.3
Total Capital Requirement, ($1000)	500,599	594,053	561,229
$/Kw	1,307	1,439	1,370
Net Operating Costs ($1000)	48,411	49,422	43,426
COE (mills/kWh)	42.5	44.3	41.1

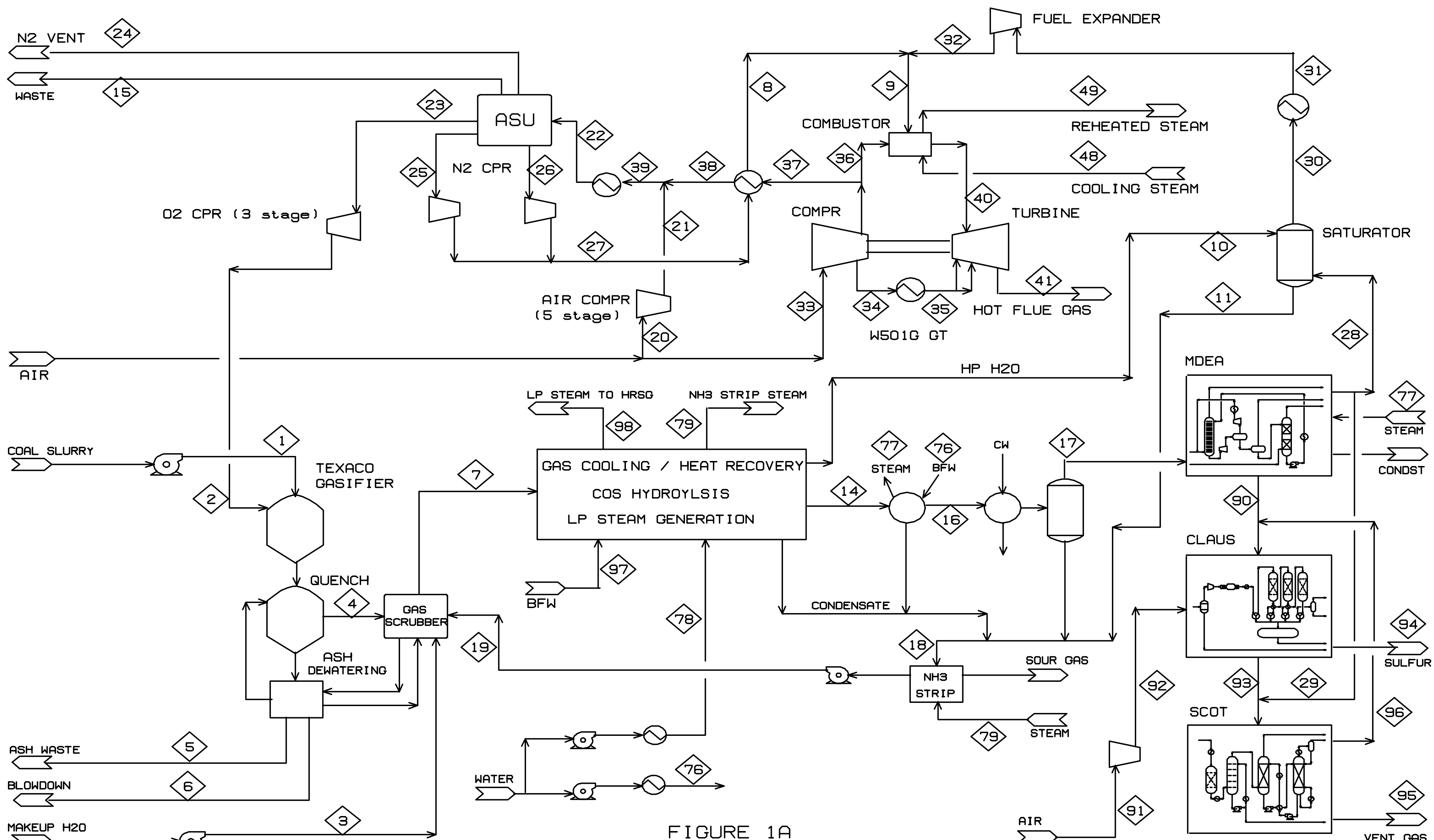

FIGURE 1A
TEXACO IGCC/QUENCH — CASE 1

FIGURE 1B

TEXACO IGCC/QUENCH - CASE 1 (CGCU/FUEL SATURATOR/W501G GT)

SUMMARY:

POWER	MW	EFFICIENCY	%
GAS TURBINE	272.7	HHV	39.7
STEAM TURBINE	152.3	LHV	41.2
MISCELLANEOUS	30.2		
AUXILIARY	11.8		
PLANT TOTAL	382.9		

STREAM	1	2	3	4	5	6	7	14	16	17	18	19	20	21	22
FLOW (LB/LB)	376407	231679	135415	1574133	52910	94958	1111176	605492	539365	502560	527803	526355	487257	485183	972440
TEMPERATURE (F)	59.6	230.5	60.4	425.3	200	200	423	325	265	103	175.3	176.5	59	204	190
PRESSURE (PSIA)	720	650	650	604.7	15	15	591	559	554	549	20	650	14.7	280	277
H (MM BTU/HR)	-1530.9	7	-931.5	-7366.8	-213.2	-635.9	-4431.9	-1599.3	-1235.7	-1060.7	-3558.3	-3554.7	-20.3	8	0

STREAM	23	24	25	26	15	710	28	29	10	11	30	31	32	8	9
FLOW (LB/LB)	231679	475781	47731	213757	5568	213757	461113	7004	505684	424871	541925	541925	541925	261488	803413
TEMPERATURE (F)	60	62	60	62	59	215.6	116	116	376.1	166	309.3	550	465.2	700	521.3
PRESSURE (PSIA)	92	91	265	91	14.7	336	524	524	559	520	510	500	333	333	333
H (MM BTU/HR)	-1.1	-5.2	-0.3	-2.3	-38.3	5.7	-957.3	-14.5	-3298.2	-2873.8	-1381.7	-1329.9	-1347.6	39.7	-1307.9

STREAM	33	34	35	36	37	38	39	40	41	48	49	76	77	78	79
FLOW (LB/LB)	4320000	527109	527109	3292155	487257	487257	972440	4095566	4622676	70000	70000	67374	67374	59743	59743
TEMPERATURE (F)	59	812.6	600	812.6	812.6	541.7	374.3	2582.8	1132.5	606.2	1055.4	255	302	255	348
PRESSURE (PSIA)	14.7	282.2	276.6	282.2	282.2	280.2	280	268.5	15.2	350	342	65	62	120	117
H (MM BTU/HR)	-187.3	75.9	47.2	474.2	70.2	36.4	44.4	-873.5	-2579.4	-388.6	-371.8	-449.3	-382.4	-398.4	-338.1

STREAM	90	91	92	93	94	95	96	97	98
FLOW (LB/LB)	36784	15133	15133	47663	6766	52155	2513	328061	328061
TEMPERATURE (F)	127.2	59	161.1	421.9	285	70	70	87.9	375
PRESSURE (PSIA)	18.5	14.7	25	26.7	14.7	17.5	17.5	40	37
H (MM BTU/HR)	-99.6	-0.6	-0.3	-125.7	-0.7	-142	-8.9	-2234.1	-1850.9

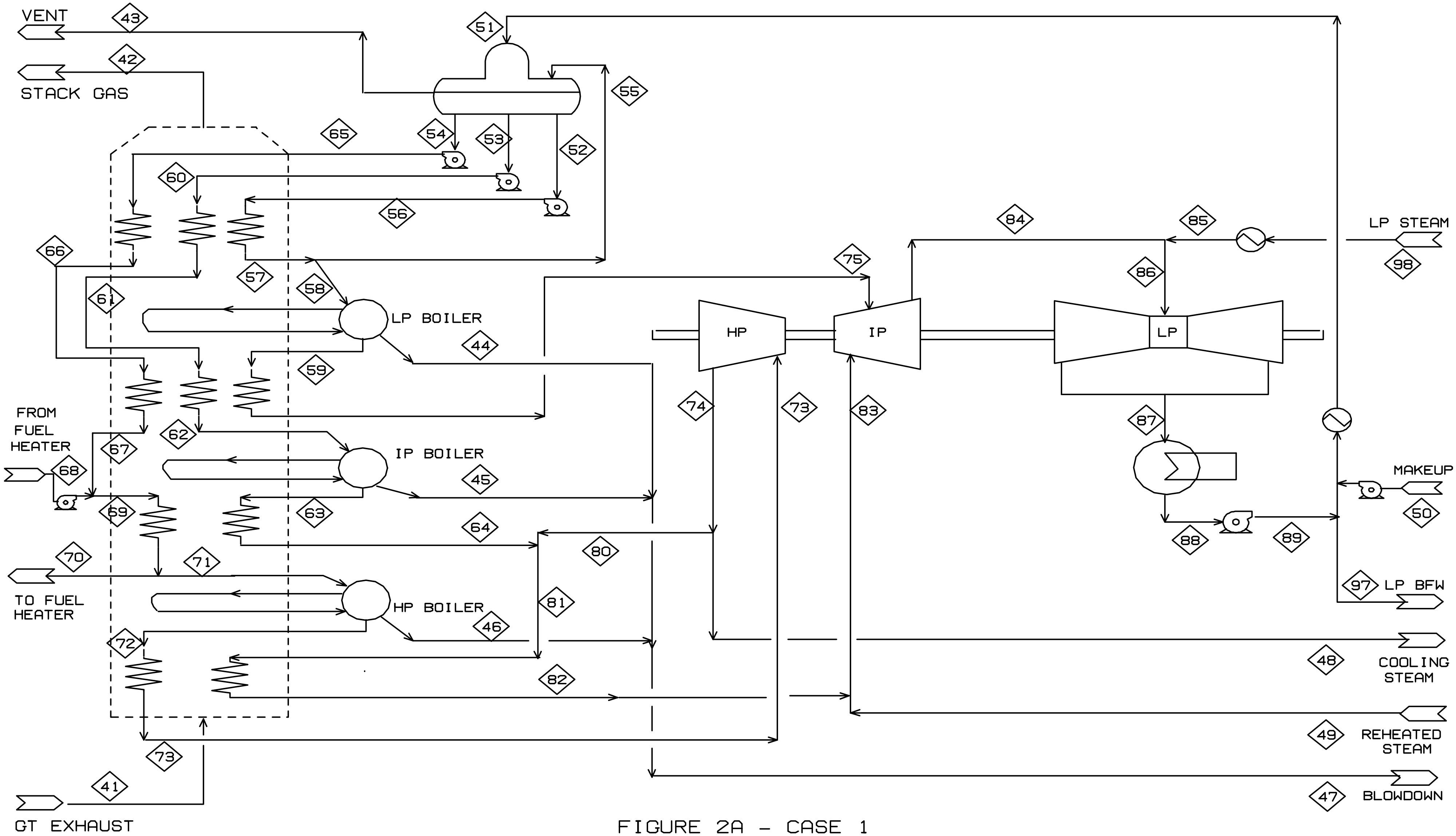

FIGURE 2A – CASE 1
TEXACO IGCC/QUENCH – STEAM CYCLE

FIGURE 2B

TEXACO IGCC/QUENCH - CASE 1 (CGCU/FUEL SATURATOR/W501G GT)

STEAM CYCLE PROCESS STREAMS

STREAM	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
FLOW (LB/HR)	4622676	4622676	7899	409	1270	5079	6757	70000	70000	14657	683624	937092	126971	507886	896224
TEMPERATURE (F)	1132.5	260	217.3	305.3	432.3	629.3	213	606.2	1055.4	80	137	217.3	217.3	217.3	286
PRESSURE (PSIA)	15.2	15	16.3	72.5	352	1910.5	15	350	342	14.7	17	16.3	16.3	16.3	76.3
H (MM BTU/HR)	-2579.4	-3664	-45.1	-2.7	-8.2	-31.5	-42.4	-388.6	-371.8	-99.9	-4622	-6260.5	-848.3	-3393	-5924.9

STREAM	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70
FLOW (LB/HR)	937092	937092	40868	40459	126971	126971	126971	125702	125702	507886	507886	507886	167407	675292	167407
TEMPERATURE (F)	217.4	286	286	305.3	218.3	286	420	432.3	620	221.4	286	420	420	420.1	620
PRESSURE (PSIA)	80.3	76.3	76.3	72.5	410.6	390	370.5	352	350	2345.6	2228.3	2116.9	1980	2015	2011.1
H (MM BTU/HR)	-6260.2	-6195	-270.2	-230	-848	-839.3	-821.4	-711.8	-696.9	-3388.3	-3355.5	-3284.9	-1082.8	-4367.6	-1041.5

STREAM	71	72	73	74	75	80	81	82	83	84	85	86	87	88	89
FLOW (LB/HR)	507886	502807	502807	502807	40459	432807	558508	558508	628508	668967	328061	997028	997028	997028	997028
TEMPERATURE (F)	620	629.3	1049.3	606.2	420	606.2	609.3	1050	1050.6	477.1	555.3	502.9	88.8	87.9	87.9
PRESSURE (PSIA)	2011.1	1910.5	1800	350	69.5	350	350	342	342	35	35	35	0.7	0.7	40
H (MM BTU/HR)	-3159.8	-2876.9	-2692.8	-2791.4	-227.6	-2402.8	-3099.7	-2968.3	-3340.2	-3740.9	-1822.1	-5563.1	-5819	-6789.9	-6789.7

STREAM	97	98
FLOW (LB/HR)	328061	328061
TEMPERATURE (F)	87.9	375
PRESSURE (PSIA)	40	37
H (MM BTU/HR)	-2234.1	-1850.9

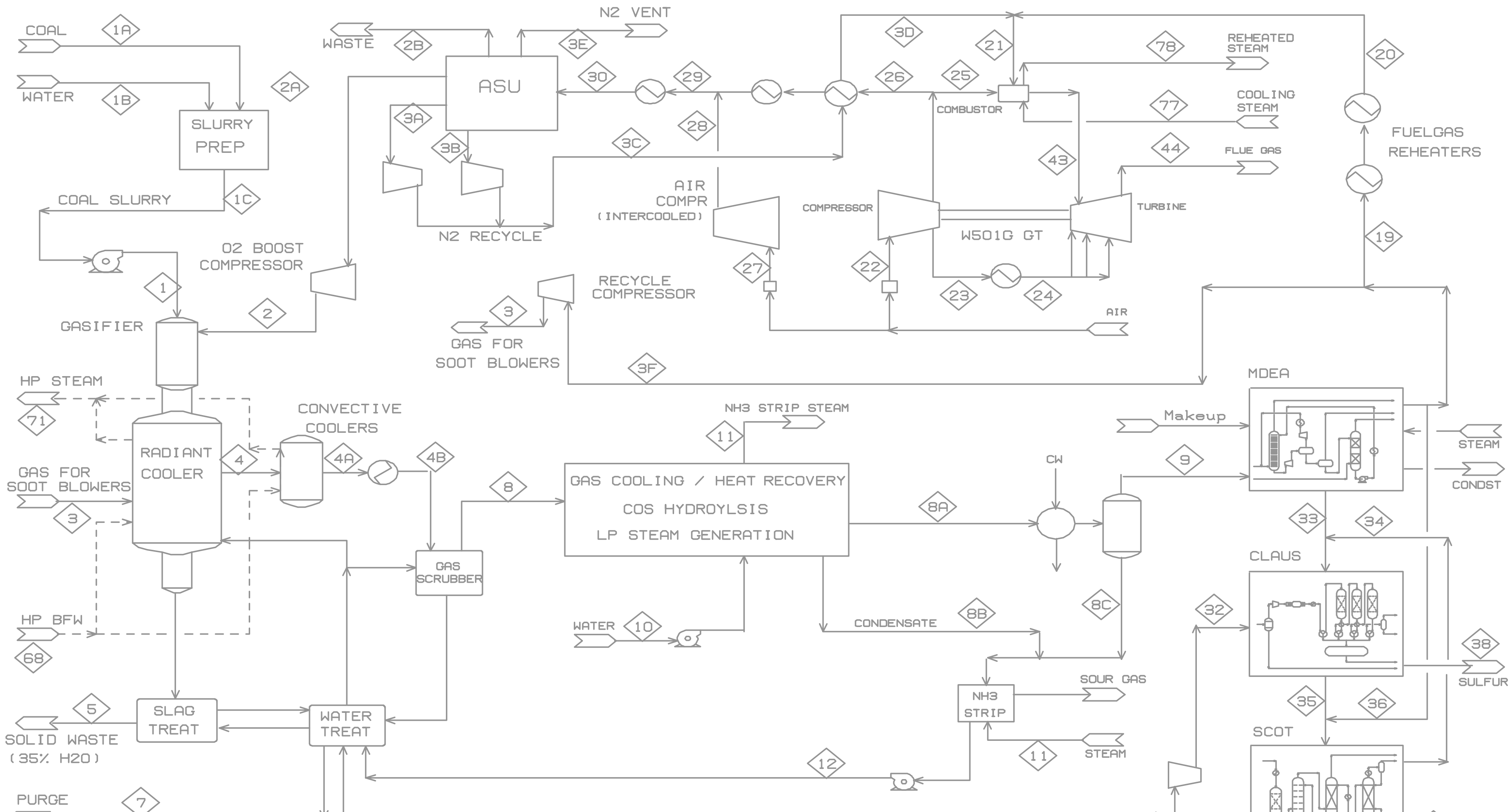

FIGURE 3A - CASE 2
TEXACO/RSC+CSC/CGCU/W501G GT

FIGURE 3B

TEXACO IGCC - CASE 2 (RADIANT+ CONVECTIVE/CGCU/W501G GT/3 PRESS STEAM CYCLE)

SUMMARY:

POWER	MW	EFFICIENCY	%
GAS TURBINE	272.4	HHV	43.5
STEAM TURBINE	191.7	LHV	45.1
MISCELLANEOUS	38.5		
AUXILIARY	12.8		
PLANT TOTAL	412.8		

STREAM	1A	1B	1C	1	2A	2B	2	3A	3B	3C	3D	3E	3F	3	4
FLOW (LB/HR)	277431	92440	369870	369870	227646	5471	227646	46900	352319	399220	399220	325218	47300	47300	626631
TEMPERATURE (F)	59	59	59	59.6	60	59	222.8	60	62	202.7	700	62	116	329.6	1500
PRESSURE (PSIA)	14.7	14.7	14.7	720	92	14.7	590	265	91	336	333	91	340	900	450
H (MM BTU/HR)	-868.6	-636.2	-1504.7	-1504.3	-1	-37.6	6.5	-0.3	-3.8	9.5	60.3	-3.5	-98.1	-94.4	-1233.7

STREAM	4A	4B	5	6	7	8	8A	8B	8C	9	10	11	12	19	20
FLOW (LB/HR)	626631	626631	38604	30514	93591	654527	554453	100074	12570	541883	45000	45000	111392	451367	451367
TEMPERATURE (F)	650	400	200	59	200	304.6	190	232.2	112.7	103	59	280	213.1	116	560.5
PRESSURE (PSIA)	427.5	420	15	14.7	15	400	374	374	20	369	14.7	37	470	340	330
H (MM BTU/HR)	-1450.1	-1510.2	-119.4	-210	-625.2	-1738.4	-1192.8	-669.1	-79.6	-1142.8	-309.7	-255.7	-747.9	-936.2	-861.2

STREAM	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
FLOW (LB/HR)	850586	4320000	527109	527109	3300635	478777	478777	476742	955520	955520	15067	15067	39729	2658	50716
TEMPERATURE (F)	612.9	59	813.3	600	813.3	813.3	59	204.1	237.7	190	59	161.2	138.4	70	421.6
PRESSURE (PSIA)	330	14.6	282.2	276.6	282.2	282.2	14.6	280	278	275	14.7	25	18.5	17.5	26.7
H (MM BTU/HR)	-801	-180.3	76.7	47.9	480.4	69.7	-20	7.8	11.9	0.7	-0.6	-0.3	-111.1	-9.5	-137.5

STREAM	36	37	38	43	44	68	71
FLOW (LB/HR)	6986	55045	6736	4151220	4678329	641608	641608
TEMPERATURE (F)	116	70	285	2581.1	1121.2	420	635
PRESSURE (PSIA)	340	17.5	14.7	268.5	15.2	2116.9	1910.5
H (MM BTU/HR)	-14.5	-154.5	-0.7	-359.9	-2063.7	-4149.7	-3663.2

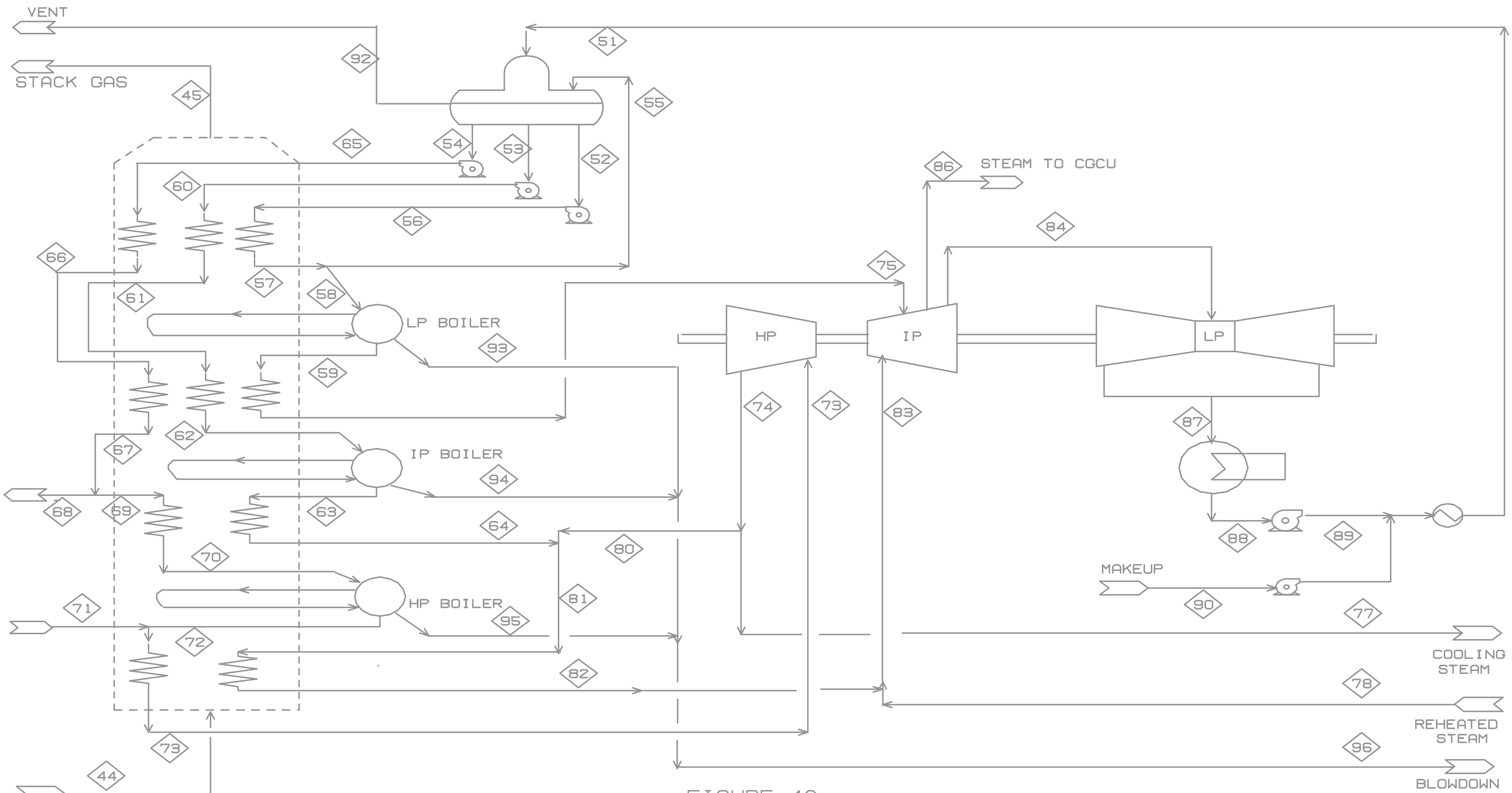

FIGURE 4A
CASE 2 - STEAM CYCLE
TEXACO/RSC+CSC/CGCU/W501G GT

FIGURE 4B

TEXACO IGCC - CASE 2 (RADIANT+ CONVECTIVE/CGCU/W501G GT/3 PRESS STEAM CYCLE)

STEAM CYCLE PROCESS STREAMS

STREAM	44	45	51	52	53	54	55	56	57	58	59	60	61	62	63
FLOW (LB/HR)	4678329	4678329	1042909	287816	263304	760462	275264	287816	287816	12552	12427	263304	263304	263304	260671
TEMPERATURE (F)	1121.2	260	205	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286	420	432.3
PRESSURE (PSIA)	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390	370.5	352
H (MM BTU/HR)	-2063.7	-3129	-6980.2	-1922.8	-1759.1	-5080.4	-1819.8	-1922.7	-1902.7	-83	-70.6	-1758.6	-1740.5	-1703.4	-1476.1

STREAM	64	65	66	67	68	69	70	71	72	73	74	75	77	78	80
FLOW (LB/HR)	260671	760462	760462	760462	641608	118855	118855	641608	117666	759274	759274	12427	70000	70000	689274
TEMPERATURE (F)	620	221.1	286	420	420	420.1	620	635	629.3	1050	606.7	420	606.7	1055.9	606.7
PRESSURE (PSIA)	350	2345.6	2228.3	2116.9	2116.9	2015	2011.1	1910.5	1910.5	1800	350	69.5	350	342	350
H (MM BTU/HR)	-1445.1	-5073.6	-5024.2	-4918.4	-4149.7	-768.7	-739.5	-3663.2	-673.2	-4066	-4215	-69.9	-388.6	-371.8	-3826.4

STREAM	81	82	83	84	86	87	88	89	90	92	93	94	95	96
FLOW (LB/HR)	949945	949945	1019945	959725	72646	945412	945412	945412	83184	6591	126	2633	1189	3947
TEMPERATURE (F)	610.4	1050	1050.4	485.2	600	88.8	87.9	87.9	80	217.3	305.3	432.3	629.3	213
PRESSURE (PSIA)	350	342	342	35	60	0.7	0.7	40	14.7	16.3	72.5	352	1910.5	15
H (MM BTU/HR)	-5271.5	-5048.7	-5420.5	-5363.2	-402	-5522.6	-6438.4	-6438.2	-567.1	-37.7	-0.8	-17	-7.4	-25.2

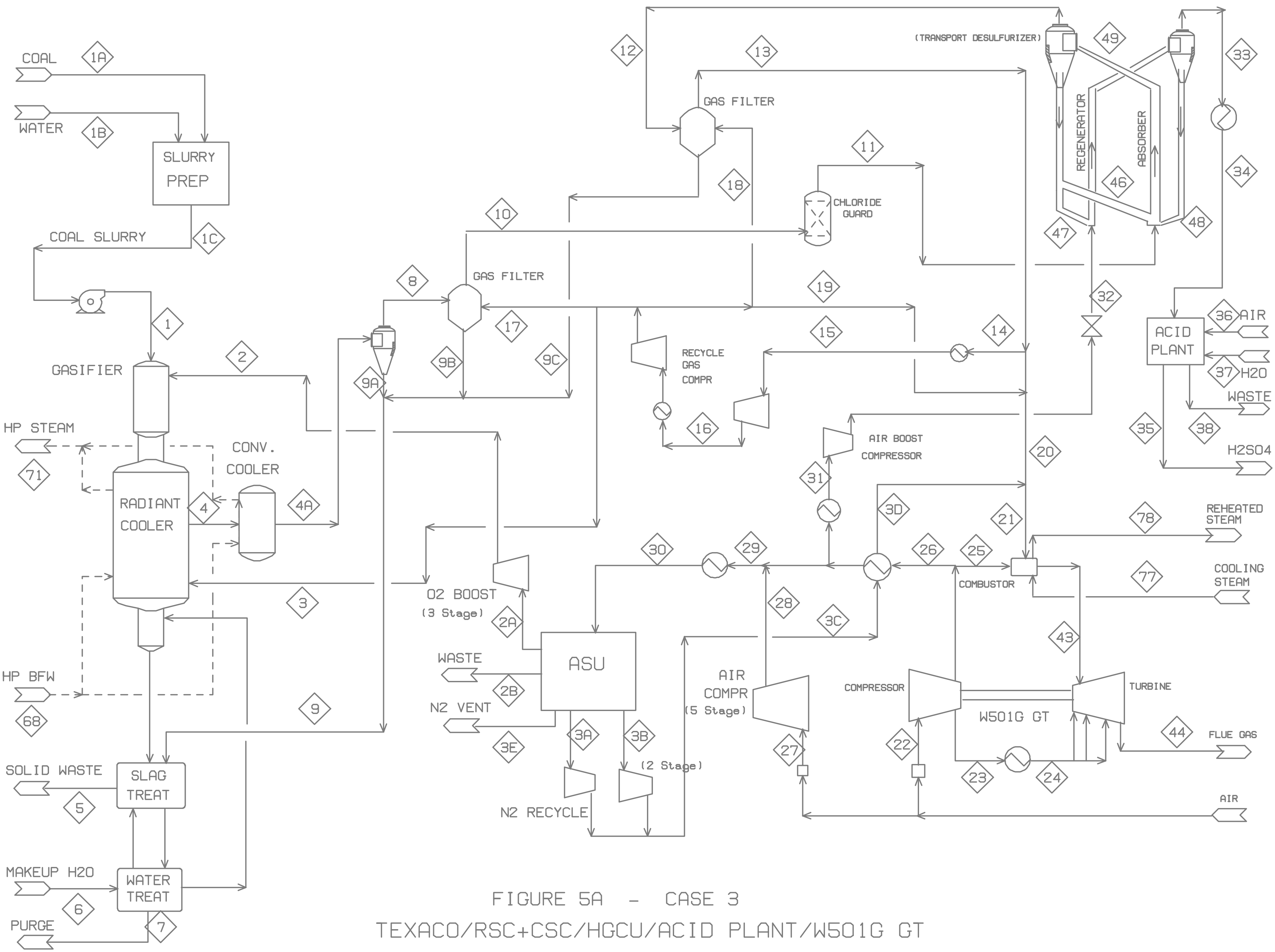

FIGURE 5A – CASE 3

TEXACO/RSC+CSC/HGCU/ACID PLANT/W501G GT

FIGURE 5B

TEXACO IGCC - CASE 3 (RADIANT+ CONVECTIVE/HGCU/W501G GT/3 PRESS STEAM CYCLE)

SUMMARY:

POWER	MW	EFFICIENCY	%
GAS TURBINE	272.1	HHV	46.5
STEAM TURBINE	183.8	LHV	48.3
MISCELLANEOUS	33.7		
AUXILIARY	12.7		
PLANT TOTAL	409.6		

STREAM	1A	1B	1C	1	2A	2B	2	3A	3B	3C	3D	3E	3	4	4A
Flow (LB/HR)	257410	85769	343179	343179	211226	5076	211226	43517	270327	313844	313844	358340	43987	581519	581519
TEMPERATURE (F)	59	59	59	59.6	60	59	222.7	60	62	200.1	700	62	371.2	1500	1004
PRESSURE (PSIA)	14.7	14.7	14.7	720	92	14.7	590	265	91	336	333	91	900	450	427.5
H (MM BTU/HR)	-805.9	-590.2	-1396.2	-1395.8	-1	-34.9	6.1	-0.3	-2.9	7.4	47.5	-3.9	-111.4	-1168.4	-1288.1

STREAM	5	6	7	8	9A	9B	9C	9	10	11	12	13	14	15	16
Flow (LB/HR)	35617	23477	14392	572343	9176	459	24	9659	579049	578294	575065	578540	55540	55540	55540
TEMPERATURE (F)	200	59	200	1004	1004	996.2	1052.9	1004.9	996.2	992.6	1057	1052.9	1052.9	300	434.8
PRESSURE (PSIA)	14.7	15	15	406	14.7	14.7	14.7	14.7	386	366	356	346	346	336	565.6
H (MM BTU/HR)	-109.4	-161.6	-96.8	-1276.1	-12	-0.6	0	-12.7	-1293.6	-1293.7	-1297.9	-1306.7	-125.4	-141.9	-139.2

STREAM	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Flow (LB/HR)	7165	3499	889	523889	837733	4320000	527109	527109	3267019	512394	444243	442352	886595	886595	68150
TEMPERATURE (F)	371.2	371.2	371.2	1051.8	953.5	59	812.6	600	812.6	812.6	59	204	356.1	190	120
PRESSURE (PSIA)	900	900	900	345	333	14.6	282.2	276.6	282.2	282.2	14.6	280	280	277	275.2
H (MM BTU/HR)	-18.1	-8.9	-2.3	-1183.5	-1136	-187.3	75.9	47.2	470.6	73.8	-18.5	7.3	36.5	0	-2.3

STREAM	32	33	34	35	36	37	38	43	44	46	47	48	49	68	71
Flow (LB/HR)	68150	71374	71374	19675	13962	3526	69184	4104750	4631859	4997251	555250	552027	6127571	504019	504019
TEMPERATURE (F)	167	1389.3	850	100	59	59	100	2581.1	1127.9	1055	1055	1389.3	1059.4	420	635
PRESSURE (PSIA)	371	361	344	16	14.7	14.7	16	268.5	15.2	356	356	361	361	2116.9	1911
H (MM BTU/HR)	-1.2	-5.1	-15	-24.7	-0.6	-24.3	-2.2	-703.9	-2407.7	-17159.4	-1906.6	-1904.7	-20357.8	-3259.8	-2877.7

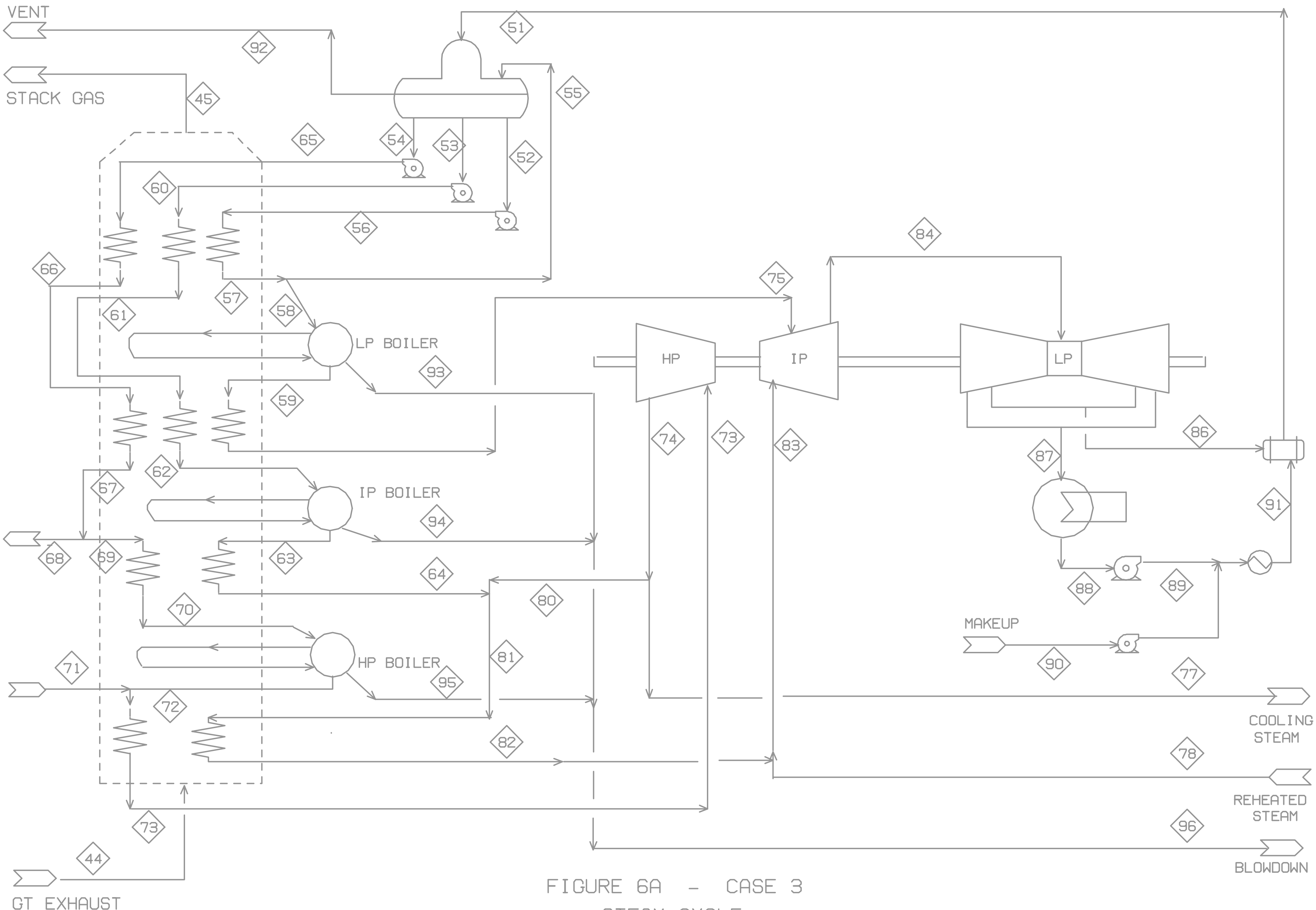

FIGURE 6A – CASE 3
STEAM CYCLE
TEXACO/RSC+CSC/HGCU/ACID PLANT/W501G GT

FIGURE 6B

TEXACO IGCC - CASE 3 (RADIANT+ CONVECTIVE/HGCU/W501G GT/3 PRESS STEAM CYCLE)

STEAM CYCLE PROCESS STREAMS

STREAM	44	45	51	52	53	54	55	56	57	58	59	60	61	62	63
FLOW (LB/HR)	4631859	4631859	983468	271412	261706	703710	259575	271412	271412	11837	11718	261706	261706	261706	259089
TEMPERATURE (F)	1127.9	259.9	205	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286	420	432.3
PRESSURE (PSIA)	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390	370.5	352
H (MM BTU/HR)	-2407.7	-3484.3	-6582.4	-1813.2	-1748.4	-4701.3	-1716	-1813.2	-1794.3	-78.3	-66.6	-1747.9	-1730	-1693.1	-1467.1

STREAM	64	65	66	67	68	69	70	71	72	73	74	75	77	78	80
FLOW (LB/HR)	259089	703710	703710	703710	504019	199691	199691	504019	197694	701713	701713	11718	70000	70000	631713
TEMPERATURE (F)	620	221.2	286	420	420	420	620	635	629.3	1049.3	606.2	420	606.2	1055.4	606.2
PRESSURE (PSIA)	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1911	1910.5	1800	350	69.5	350	342	350
H (MM BTU/HR)	-1436.4	-4694.9	-4649.2	-4551.4	-3259.8	-1291.5	-1242.4	-2877.7	-1131.1	-3758	-3895.7	-65.9	-388.6	-371.8	-3507

STREAM	81	82	83	84	86	87	88	89	90	91	92	93	94	95	96
FLOW (LB/HR)	890802	890802	960802	972520	50433	922087	922087	922087	10948	933035	6215	118	2617	1997	4732
TEMPERATURE (F)	610.2	1050	1050.4	485.2	352.8	88.8	87.9	87.9	60	148.6	217.3	305.3	432.3	629.3	213
PRESSURE (PSIA)	350	342	342	35	17	0.7	0.7	40	14.7	17	16.3	72.5	352	1910.5	15
H (MM BTU/HR)	-4943.4	-4734.4	-5106.2	-5434.7	-284.9	-5386.4	-6279.5	-6279.4	-74.9	-6297.5	-35.5	-0.8	-16.9	-12.4	-30.1

1. Process Descriptions

IGCC Base Cases have been developed for three Texaco Gasifier cases that differ primarily in how the generated fuel syngas is cooled and in the gas cleanup sections. For Case 1, the gasifier system includes a high-pressure water quench section that rapidly reduces the solid/gas mixture to approximately 425 °F (605 psia). The Texaco Radiant/Convective design is used in Cases 2 and 3. In this design, the mix of gas/solids from the gasifier enters a radiant syngas cooling (RSC) system, (perhaps larger in size than the gasifier vessel), where cooling to approximately 1500 °F is accomplished by generating high-pressure steam. For Case 2, a convective syngas cooling (CSC) /gas scrubbing system cools the raw fuel stream to about 305 °F (400 psia) by generating additional steam and by reheating the clean fuel gas from the CGCU section. For Case 3, the CSC is used only to generate steam and cools the syngas to approximately 1004 °F. Cases 1 and 2 use a gas scrubber and a low temperature gas cooling/heat recovery section to reduce the raw fuel gas stream to 103 °F prior to entering a CGCU section for sulfur removal. In Case 3, the raw fuel gas is cleaned for particulates using cyclones and gas filters before entering a chloride guard bed. The sulfur removal is accomplished in a HGCU section and sulfur is recovered using a sulfuric acid plant.

The composition for the as-received Illinois #6 Coal fed to the slurry process is:

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 three cases are given in following sections. In Table 2, the processes used are compared.

Table 2 : Texaco IGCC Base Cases Process Section Comparison

PROCESS SECTION	CASE 1	CASE 2	CASE 3
Texaco Gasifier Exit Temp / Press Slurry (% Solids):	 2500 °F / 605 psia 66.5	 2500 °F / 475 psia 66.5	 2500 °F / 475 psia 66.5
Raw Fuel (syngas) Cooling Mode	Quench (425 °F)	RSC (1500 °F) CSC (400 °F)	RSC (1500 °F) CSC (1004 °F)
Air Separation Plant Inlet Air Press (psia): O2 / N2 Press (psia):	50 % Integration GT 277 650 / 336	50 % Integration GT 277 590 / 336	50 % Integration GT 277 590 / 336
Solid Waste /Particulates	Slag Treatment, Gas Scrubber	Slag Treatment, Gas Scrubber	Slag Treatment, Cyclones, Gas Filters
Low Temp Gas Cooling/Heat Recovery	COS Hydrolysis, LP & NH3 Strip Steam, BFW Heating	COS Hydrolysis, NH3 Strip Steam, BFW Heating	N/A
Chloride/NH3 Removal	Water Condensate Treatment, NH3 Strip	Water Condensate Treatment, NH3 Strip	Chloride Guard Bed
Sulfur Removal	CGCU-MDEA/CLAUS/SCOT (elemental sulfur)	CGCU - MDEA/CLAUS/SCOT (elemental sulfur)	HGCU - Transport Desulfurization, Acid Plant (sulfuric acid)
Clean Fuel Gas / Gas Addition	Clean Fuel Gas Saturator (H2O), N2 Recycle from ASU	N2 Recycle from ASU	N2 Recycle from ASU
Gas Turbine - Power (MWe): - PR / TIT (F):	modified W501 G 272 19.37 / 2583	same as Case 1	same as Case 1
Steam Cycle - Turb Press: 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	same as Case 1

1.1 Texaco Gasifier

The coal, (Illinois #6 for the cases considered), is crushed and mixed with water to produce a slurry that is 33.5% by weight water. This slurry is pumped into the gasifier along with oxygen. The gasifier operates in a pressurized, downflow, entrained design and gasification takes place rapidly at temperatures in excess of 2300 °F. The raw fuel gas produced is mainly composed of H_2, CO, CO_2, and H_2O. The coal's sulfur is primarily converted to H_2S and a smaller quantity of COS. This raw fuel gas leaves the gasifier at 2300 - 2700 °F along with molten ash and a small quantity of unburned carbon. No hydrocarbon liquids are generated.
Depending on the design, this gas/molten solids stream enters either a direct quench (Case 1) or a radiant syngas cooler (RSC) and convective syngas cooler (CSC) sections. (Case 2 and Case 3).

The Quench design consists of a large water pool that cools the gas and removes solidified ash particles. The cooled raw fuel gas enters a gas scrubbing section to remove additional fine solids before exiting the gasification section to a gas cooling section. The RSC/CSC design recovers sensible heat for high-pressure steam generation in the radiant section. The ash/solid stream exits the RSC into a water quench pool and the raw fuel gas stream enters a convective cooler at about 1500 °F. For Case 2, The CSC section generates additional steam and reheats the clean fuel gas. The cooled gas then enters a gas scrubbing section before being sent to a gas cooling section. (Similar to Case 1). For Case 3, the CSC section generates only steam while lowering the raw fuel gas temperature to only 1004 °F. A dry system consisting of cyclones and filters is used to remove remaining solids. Figures 1, 3 and 5 illustrate the gasification section relationship to other process sections. In Table 3, gasifier conditions are listed for the three Texaco IGCC cases.

1.1 Air Separation Plant (ASU)

For all 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 nitrogen recycle is adjusted for each case to yield a net gas turbine power of approximately 272 MWe. The amount of nitrogen recycled is less than 55% for all cases. This implies that a possibility exist that two ASU plants could be run in parallel for these cases. A high-pressure oxygen plant with nearly all the nitrogen recycled and a lower pressure oxygen plant with all the nitrogen vented. Additionally, the ASU design for Case 2 and 3 could be modified to supply a small high purity nitrogen stream (99.9%) for use as soot blower gas in the gasifier's RSC section instead of using a recycle of clean flue gas. Table 4 lists some of the key parameters for the ASU designs.

Table 3. Texaco IGCC Base Cases - Gasifier Conditions

	CASE 1 Quench/CGCU	**CASE 2 RSC+CSC/CGCU**	**CASE 3 RSC+CSC/HGCU**
Coal (dry) (tons/day):	3011	2959	2745
Coal (tons/day):	3389	3329	3089
Slurry Water (tons/day):	1129	1109	1029
Gasifier Pressure (Psia):	615	475	475
Gasifier Temp (°F):	2500	2500	2500
Raw Fuel Gas Temp (°F)			
- Quench Exit:	425		
- RSC Exit:		1500	1500
- CSC Exit:		400	1004
- To Gas Cooling:	423	305	
- To Cyclone:			1004
Heating Value (Btu/Scf)			
(from gasifier)			
- LHV	224	224	224
- HHV	240	240	240
Flowrates (lb/hr)			
Coal Slurry :	376407	369870	343179
Oxidant (95% O2) :	231679	227646	211226
Solid Waste Slurry :	52910	38604	35617
Water Purge :	94958	93591	14391
Makeup Water :	135415	30514	23477

Table 4. Texaco IGCC Base Cases - ASU Summary

	Case 1 Quench/CGCU	Case 2 RSC+CSC/CGCU	Case 3 RSC+CSC/HGCU
% Air from Gas Turbine	50%	50%	50%
Air Inlet Press (psia)	277	275	277
Total Air Flowrate (lb/hr)	972440	955520	886595
Oxidant Stream			
- Flowrate (lb/hr):	231679	227646	211226
- Purity (mole % O2):	95.0	95.0	95.0
- ASU Press (psia):	92	92	92
- Boost Compr Pres (psia):	650	590	590
Nitrogen Stream			
- Flowrate (lb/hr):	261488	399220	313844
- Purity (mole % N2):	98.9	98.9	98.9
- ASU Press (psia):	91 / 265	91 / 265	91 / 265
- Boost Compr Pres (psia):	336	336	336
- % Recycled to GT:	35	55	47
- GT Recycle Temp (F):	700	700	700
Power Requirements (MWe)			
- Air Boost Compressor:	21.3	20.9	19.4
- O2 Boost Compressor:	6.7	6.2	5.8
- N2 Boost Compressor:	4.4	7.1	5.5

1.3 Gas Cooling/Heat Recovery/Hydrolysis/Gas Saturation (CASE 1 and CASE 2)

For Case 1 and Case 2, the raw fuel gas from the gas scrubber is cooled in a series of heat exchangers to 103 °F and sent to the CGCU section. Any hydrogen chloride and ammonia is assumed to be in the condensate from these heat exchangers, which is then sent to an ammonia strip unit for further treatment. This section also contains a catalytic hydrolyzer in which the carbonyl sulfide is converted to hydrogen sulfide.

For Case 1, heat recovered in the heat exchanger network is used to generate low-pressure steam for the HRSG and the ammonia strip unit. Additionally, low quality heat is used for BFW heating. The clean fuel gas from the CGCU is saturated with high-pressure water condensate from the gas cooling unit before being sent to the gas turbine. This lowers the amount of nitrogen recycle from the ASU needed to achieve the turbine power requirement to about 35%.

For Case 2, the Texaco Gasifier was run at a lower pressure when compared to Case 1. This results in the raw fuel gas from the gas scrubber being at a lower pressure and lower temperature. The heat recovery is only useful for generating strip steam and BFW heating. Condensate is at too low a temperature to use for saturating the clean fuel gas.

1.4 Cold Gas Cleanup Unit (CGCU) (CASE 1 and CASE 2)

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 low temperature heat recovery unit 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 128 °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. Texaco IGCC Base Cases - CGCU Conditions

	Case 1 Quench/CGCU	Case 2 RSC+CSC/CGCU
Sulfur Balance: (lb sulfur/hr)		
- MDEA Feed	6837.2	6807.5
- Acidgas to Claus	6775.2	6745.8
- Cleaned Fuel Gas	61.1	60.9
- Sulfur Product	6765.6	6736.1
- SCOT Vent Gas	10.5	10.5
Key Conditions		
- PPMV to CGCU	8769	8073
- PPMV Clean Fuel Gas	82.7	76.0
- Sulfur Recovery (weight %)	99.0	99.0
- Steam Requirements (lb/hr)	67374	72646
- Power Requirements (KWe)	772	878

1.5 Fine Particulate Removal/ Chloride Guard Bed - CASE 3

For Case 3, the raw fuel gas (at 1004 °F) from the convective syngas cooler enters a cyclone and gas filter section to remove remaining particulates. This system cleans the gas leaving the moisture content unchanged and sends the stream to a chloride guard bed for hydrogen chloride removal. The resulting fuel gas stream is sent to the HGCU section for sulfur removal. An additional 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. A recycle of a small portion of clean fuel gas from the HGCU section is compressed and used for pressurizing gas filters and for gas for soot blowers in the RSC gasifier section.

1.6 Transport Desulfurization HGCU - Case 3

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 366 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 exit temperature is 1057 °F . This cleaned fuel gas enters a gas filter to capture any particulates and with the exception of a small portion, which is split off and recycled, (as described in the previous section) is sent directly to the gas turbine combustor.

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 inlet temperature of the air 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 3

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. Texaco Gasifier IGGC Base Case 3 - HGCU Conditions

Sulfur Balance Information:	
	Flowrate (lb/hr)
Sulfur in Raw Fuel Gas	6452.6
Sulfur in Regenerator Waste	6433.1
Sulfur in Clean Fuel Gas	8.8
(ASPEN Convergence Error Sulfur %)	0.165
PPMV of Sulfur in Raw Fuel Gas	7055

PPMV of Sulfur in Clean Fuel Gas	10	(Set in simulation)
HGCU Sulfur Capture Eff. (weight %)	99.7	
Mole % SO_2 in Regenerator Waste	8.9	
Regenerator Exit Gas Temp (°F)	1389	
Regenerator Air Temp (°F)	167	

HGCU Solids:	**Flowrate (lb/hr)**	**Sorbent Utilization** *
To Absorber Rise	5,549,280	.444
From Absorber Separator	5,552,510	.450
To Regenerator Riser	555,250	.450
From Regenerator. Separator	552,027	.389

Ratio: Solids to Absorber/Solids to Regenerator = 10.0

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

1.8 Gas Turbine

All 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. 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 low-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. Texaco IGCC Base Cases - Fuel Gas Composition (Mole %)

TEXACO Gas Cooling Gas Cleaning	CASE 1 Quench/ CGCU (No Nitrogen Recycle from ASU)	CASE 2 RSC+ SCS/ CGCU (No Nitrogen Recycle from ASU)	CASE 3 RSC+ SCS/ HGCU (No Nitrogen Recycle from ASU)	CASE 1 Quench/ CGCU (Nitrogen Recycle from ASU)	CASE 2 RSC+ SCS/ CGCU (Nitrogen Recycle from ASU)	CASE 3 RSC+ SCS/ HGCU (Nitrogen Recycle from ASU)
Mole %:						
O2	-	-	-	0.16	0.23	0.18
N2	0.90	1.07	0.90	25.70	38.80	30.40
Ar	0.72	0.86	0.74	0.64	0.67	0.63
H2	31.40	37.50	30.80	23.50	23.00	21.50
CO	41.60	49.60	41.80	31.10	30.50	29.20
CO2	8.80	10.40	10.20	6.60	6.40	7.10
H2O	16.50	0.44	15.30	12.30	0.31	10.70
CH4	0.07	0.08	0.08	0.05	0.05	0.06
H2S	204 PPMV	70 PPMV	9.3 PPMV	152 PPMV	43 PPMV	6.5 PPMV
COS	7 PPMV	6 PPMV	0.2 PPMV	5 PPMV	3 PPMV	0.2 PPMV
NH3	304 PPMV	-	0.14	227 PPMV	-	0.10
HCL	9 PPMV	-	-	7 PPMV	-	-
Heating Value (HHV) (Btu/Scf)	236.00	282.00	236.00	176.00	171.00	164.00

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

TEXACO Gas Cooling Gas Cleaning	CASE 1 Quench CGCU	CASE 2 RSC+CSC CGCU	CASE 3 RSC+CSC HGCU
Pressure (psia)			
- to Filter	14.7	* (Same as Case 1)	* (Same as Case 1)
- Compressor inlet	14.57	*	*
- Compressor outlet	282	*	*
- Combustor exit	269	*	*
- Expander exhaust	15.2	*	*
Pressure Ratio	19.4	*	*

TEXACO **Gas Cooling** **Gas Cleaning**	**CASE 1** **Quench** **CGCU**	**CASE 2** **RSC+CSC** **CGCU**	**CASE 3** **RSC+CSC** **HGCU**
Flowrates (lb/hr)			
- Compr inlet Air	4,320,000	*	*
- Fuel Gas	541,925	451,367	523,888
- Nitrogen Recycle	261,488	399,220	313,844
- Bleed Air to ASU	487,257	489,896	444,243
- Bleed Air to HGCU	N/A	N/A	68,150
- Air Cooling Bleed	527,109	*	*
- Air Compr Leakage	13,478	*	*
- Steam Combustor Duct Cooling	70,000	*	*
- Expander Exhaust Gas to HRSG	4,622,680	4,678,330	4,631,860
Temperature (°F)			
- Inlet Air	59	*	*
- Compressor outlet	813	*	*
- Nitrogen Recycle	700	*	*
- Fuel Gas	465	561	1052
- Combustor exhaust	2613	2611	2610
- Turbine inlet	2583	2581	2581
- Turbine exhaust	1132	1121	1128
Power (MWe)			
- Compressor	- 237.2	-237.2	-237.2
- Expander	513.8	513.4	513.2
- Generator Loss	- 3.9	- 3.9	-3.9
- Net Gas Turbine	272.6	272.4	272.1
- Fuel Expander	5.1	N/A	N/A

1.9 Steam Cycle

The steam cycle used for the three 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.

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

The three cases' differences are related to the integration possible with the gasifier island sections. These include:

- In Case 1, the gasifier's Quench design results in no high quality heat being available for generating high pressure steam from the raw fuel gas. Case 2 & 3, which use radiant and convective syngas coolers, use a bleed of high pressure boiler feedwater from the HRSG which is returned as saturated high pressure steam for superheating.

- Case 1 and Case 2 both use CGCU but the higher gasifier pressure used in Case 1 results in differences in the low quality heat recovery sections. Both provide sufficient heat for reheating the condensate from the steam condenser and for the ammonia stripping unit. Additionally, the higher pressure Case 1 has heat of sufficient quality (i.e. high enough temperature) to be used for generating low pressure steam for use in the CGCU section and for use in the low pressure steam turbine section. Case 2 requires a low pressure steam bleed from the steam cycle to meet CGCU requirements.
- For Case 3, which uses HGCU, the available heat for condensate reheating is not sufficient to obtain the deaerator design inlet temperature. To obtain the required temperature, a bleed of low pressure steam is extracted from the low pressure steam turbine section and mixed with the condensate.

- A bleed of high pressure boiler feed water is used in Case 1 for reheating the clean fuel gas from the CGCU section. This was the only convenient means for this case. The cooled boiler feedwater is re-pumped to the HRSG.

In Figures 2, 4, and 6 the steam cycle and process flows are provided for the three cases. The primary heat recovered is from the exhaust gas stream of the gas turbine and the syngas coolers. Additionally, heat is integrated from the gas turbine cooling air chiller, from cooling the gasifier fuel gas (see above), 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. High pressure BFW for reheating the fuel gas (Case 1) is extracted after the third high pressure economizer section. 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.

Table 9. Texaco 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 Pressure (psia)	Saturation Temp (°F)	HRSG Approach Delta Temp (°F) CASE 1	CASE 2	CASE 3
Low	72.5	305	45	29	25
Intermediate	352	432	26	33	21
High	1911	629	61	58	61

Power Production (MWe)	CASE 1 Quench/CGCU	CASE 2 RSC+CSC/CGCU	CASE 3 RSC+CSC/HGCU
Steam Turbines	154.7	194.6	186.6
Generator Loss	- 2.3	- 2.9	- 2.8
Net Steam Turbines	152.3	191.7	183.8
Pumps	- 1.6	- 2.2	- 2.1

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 three Texaco IGCC cases.

Table 10. Texaco IGCC Base Cases - Power Production

	CASE 1 Quench CGCU	CASE 2 RSC+CSC CGCU	CASE 3 RSC+CSC HGCU
Gas Turbine (MWe)	272.7	272.4	272.1
Steam Turbine (MWe)	152.3	191.7	183.8
Miscellaneous (MWe)	-30.2	-38.5	-33.7

Auxiliary (MWe)	-11.8	-12.8	-12.7
Plant Total (MWe)	382.9	412.8	409.6
Overall Process Efficiency (HHV, %):	39.7	43.5	46.5
Overall Process Efficiency (LHV, %):	41.2	45.1	48.3

2. Simulation Development

The Texaco IGCC gasification section was developed based on information available in several EPRI reports (AP-3109 [1993] and AP-3486 [1984]) and a number of internal communications provided by Texaco and General Electric Company to FETC. The models for the gas turbine (W501G) and the steam cycle were based on previously developed ASPEN simulations (e.g. Texaco Quench 1997 ASPEN PLUS Simulation). 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 three 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 Texaco 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 at the end of the report. All costs are reported in 1st Quarter 1999 dollars.

3.1 Coal Slurry Preparation

The coal slurry preparation section includes costs for coal hoppers, feeders, conveyors, and sampling and feed systems. The coal flow rate for Case 3, Texaco Radiant + Convective HGCU, is 3089 tons per day (Illinois #6 coal), resulting in a section cost of $25.9 million. The coal flow rate for Case 2, Texaco Radiant + Convective CGCU, is 3329 tons per day, resulting in a cost of $27.3 million. The coal flow rate for Case 1, Texaco Quench CGCU, is 3389 tons per day, resulting in a higher cost of $27.7 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. All three systems use a high-pressure air separation unit. The oxygen plant for Case 3 produces 2535 tons per day oxygen with a cost of $51 million. The oxygen plant for Case 2 produces 2727 tons per day oxygen with a cost of $53.8 million. The oxygen plant for Case 1 produces 2780 tons per day oxygen with a cost of $53.6 million.

3.3 Texaco Gasifier

The cost for the gasifiers was derived from a previous Texaco report[2] and is dependent on the cooling process used within the gasifier. All three cases are based on one gasification train with a nominal capacity of 3000 tons per day. Case 2 uses the convective cooler to cool the gas down to 650 °F. The cost of $79 million was based on a similar Texaco case. Case 3 only uses the convective cooler to cool the gas to 1000 °F. No similar case was found, so the cost was derived from a combination of two other cases, providing some uncertainty in the cost of $63.6 million. Case 1 does not use the radiant and convective coolers, resulting in a much lower cost basis. The cost of $32.9 million was based on a similar case.

3.4 Low Temperature Gas Cooling and Gas Saturation (Cold Gas cases only)

The cost for the low temperature cooling and gas saturation section includes several heat exchangers, separators, the saturator, fuel gas reheaters, and the turbine expander. The cost for Case 2 is $10.6 million (no saturator or expander is used). The cost for Case 1 is $17.5 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 Case 2 is $5.6 million. The cost for Case 1 is $5.4 million.

The cost for the Claus/SCOT sulfur recovery and tail gas treating units for Case 2 is based on 89 tons per day of sulfur entering the unit. The total cost for both units is $14.4 million. The cost for Case 1 is based on 88 tons per day of sulfur entering the unit. The total cost for both units is $14.4 million.

3.6 Gas Conditioning (Hot Gas case only)

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2 "Cost and Performance for Commercial Applications of Texaco-Based Gasification-Combined-Cycle Plants," EPRI AP-3486, Volume 2, Prepared by Flour Engineers, Inc. April 1984.

The gas conditioning section includes the cyclones, gas filters and chloride guard beds. The cost for Case 3 is $13 million and is based on one process train. 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 Case 3 is $8 million and is based on one process train. 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 236 tons per day of sulfuric acid and costs $18.7 million.

3.9 Gas Turbine Section

[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.

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 271.1 MW_e, 272.4 MW_e, and 272.7 MW_e for Case 3, Case 2, and Case 1, respectively, all 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. Case 3 steam turbine power is 183.8 MW_e, with a combined section cost of $49.7 million. Case 2 steam turbine power is 191.7 MW_e, with a combined section cost of $50.8 million. Case 1 steam turbine power is 152.3 MW_e with a combined section cost of $45.5 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 Texaco Radiant + Convective HGCU case is $561,229,000 or $1370/kW, compared to $594,053,000 or $1439/kW for the Texaco Radiant + Convective CGCU, and $500,599,000 or $1307/kW for the Texaco Quench case. The levelized cost of electricity for the HGCU case in constant dollars is 41.1 mills/kWh, compared to 44.3 mills/kWh for the Radiant + Convective CGCU case and 42.5 mills/kWh for the Quench CGCU case.

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

Consumable Material Prices	
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	4.0% Return
			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

Texaco Quench with CGCU CASE 1 383 MW POWER PLANT
1st Q 1999 Dollar

Total Plant Investment		PROCESS	PROCESS	COST, K$
AREA NO	PLANT SECTION DESCRIPTION	CONT, %	CONT, K$	W/O CONT
11	Coal Slurry Preparation	0	$0	$27,654
12	Oxygen Plant	0	$0	$53,558
12	Texaco Gasifier (Quench)	0	$0	$32,914
14	Low Temperature Gas Cooling/Gas Saturation	0	$0	$17,526
14	MDEA	0	$0	$5,407
14	Claus	0	$0	$10,145
14	SCOT	0	$0	$4,290
15	Gas Turbine System	5	$2,706	$54,116
15	HRSG/Steam Turbine	0	$0	$45,476
18	Water Systems	0	$0	$17,827
30	Civil/Structural/Architectural	0	$0	$23,100
40	Piping	0	$0	$17,827
50	Control/ Instrumentation	0	$0	$6,528
60	Electrical	0	$0	$20,087

	Subtotal, Process Plant Cost	$336,455
Engineering Fees		$33,645
Process Contingency (Using cont. listed)		$2,706
Project Contingency, 15 % Proc Plt & Gen Plt Fac		$50,468
	Total Plant Cost (TPC)	$423,274
Plant Construction Period, 4.0	Years (1 or more)	
Construction Interest Rate, 11.2	%	
Adjustment for Interest and Inflation		$53,133
	Total Plant Investment (TPI)	$476,408
Prepaid Royalties		$1,682
Initial Catalyst and Chemical Inventory		$76
Startup Costs		$11,896
Spare Parts		$2,116
Working Capital		$7,120
Land, 200 Acres		$1,300
	Total Capital Requirement (TCR)	$500,599
	$/kW	1307

ANNUAL OPERATING COSTS – CASE 1

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,389	T/D	$29.40	/T	$30,913
Consumable Materials					
Water	4,333	T/D	$0.19	/T	$255
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	635	T/D	$8.00	/T	$1,576
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,454
Maintenance Costs	2.2%				$9,312
Royalties					$309
Other Operating Costs					$818
	Total Operating Costs				$50,300
By-Product Credits					
Sulfur	81.2	T/D	$75.00	/T	$1,889
____________________	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				$1,889
	Net Operating Costs				$48,411

BASES AND ASSUMPTIONS – CASE 1

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	110486	T	$0.19	/T	$21
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					$76

Startup costs			
Plant modifications,	2	% TPI	$9,528
Operating costs			$1,621
Fuel			$747
		Total Startup Costs	$11,896
Working capital			
Fuel & Consumables inv	60	days supply	$6,064
By-Product inventory	30	days supply	$183
Direct expenses	30	days	$874
		Total Working Capital	$7,120

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 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	31.4	26.1
Fuel Costs	11.8	10.3
Consumables	0.8	0.7
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-0.8	-0.7
Total Cost of Electricity	50.3	42.5

Texaco (Radiant+Convective) with CGCU CASE 2 413 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 Slurry Preparation	0	$0	$27,310
12	Oxygen Plant	0	$0	$53,821
12	Texaco Gasifier (RSC+CSC)	0	$0	$79,031
12	Soot Blower Recycle Compression	5	$175	$3,495
14	Low Temperature Gas Cooling	0	$0	$10,584
14	MDEA	0	$0	$5,632
14	Claus	0	$0	$10,124
14	SCOT	0	$0	$4,282
15	Gas Turbine System	5	$2,703	$54,056
15	HRSG/Steam Turbine	0	$0	$50,841
18	Water Systems	0	$0	$21,241
30	Civil/Structural/Architectural	0	$0	$27,524
40	Piping	0	$0	$21,241
50	Control/ Instrumentation	0	$0	$7,779
60	Electrical	0	$0	$23,934

	Subtotal, Process Plant Cost	$400,896
Engineering Fees		$40,090
Process Contingency (Using cont. listed)		$2,878
Project Contingency, 15 % Proc Plt & Gen Plt Fac		$60,134
	Total Plant Cost (TPC)	$503,997
Plant Construction Period, 4.0	Years (1 or more)	
Construction Interest Rate, 11.2	%	
Adjustment for Interest and Inflation		$63,266
	Total Plant Investment (TPI)	$567,263
Prepaid Royalties		$2,004
Initial Catalyst and Chemical Inventory		$70
Startup Costs		$13,820
Spare Parts		$2,520
Working Capital		$7,075
Land, 200 Acres		$1,300
	Total Capital Requirement (TCR)	$594,053
	$/kW	1439

ANNUAL OPERATING COSTS – CASE 2

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,329	T/D	$29.40	/T	$30,366
Consumable Materials					
Water	3,009	T/D	$0.19	/T	$177
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	463	T/D	$8.00	/T	$1,150
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,667
Maintenance Costs	2.2%				$11,088
Royalties					$304
Other Operating Costs					$889
	Total Operating Costs				$51,303
By-Product Credits					
Sulfur	80.8	T/D	$75.00	/T	$1,881
____________________	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				$1,881
	Net Operating Costs				$49,422

BASES AND ASSUMPTIONS – CASE 2

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	76734	T	$0.19	/T	$15
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					$70

Startup costs			
Plant modifications,	2	% TPI	$11,345
Operating costs			$1,741
Fuel			$734
		Total Startup Costs	$13,820
Working capital			
Fuel & Consumables inv	60	days supply	$5,943
By-Product inventory	30	days supply	$182
Direct expenses	30	days	$950
		Total Working Capital	$7,075

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	34.6	28.7
Fuel Costs	10.8	9.4
Consumables	0.6	0.5
Fixed Operating & Maintenance	6.2	5.4
Variable Operating & Maintenance	1.1	0.9
By-product	-0.7	-0.6
Total Cost of Electricity	52.5	44.3

Texaco (Radiant+Convective) with HGCU CASE 3 410 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 Slurry Preparation	0	$0	$25,917
12	Oxygen Plant	0	$0	$51,046
12	Texaco Gasifier (RSC+CSC)	0	$0	$63,637
12	Recycle Gas Compression	5	$223	$4,464
14	Gas Conditioning	10	$1,299	$12,988
14	Regeneration Air Boost Compressor	0	$0	$940
14	Transport Desulfurizer	15	$1,205	$8,031
14	Sulfuric Acid Plant	0	$0	$18,690
15	Gas Turbine System	5	$2,700	$53,997
15	HRSG/Steam Turbine	0	$0	$49,670
18	Water Systems	0	$0	$14,758
30	Civil/Structural/Architectural	0	$0	$26,623
40	Piping	0	$0	$14,758
50	Control/ Instrumentation	0	$0	$7,524
60	Electrical	0	$0	$23,150

		Subtotal, Process Plant Cost		$376,195
Engineering Fees				$37,619
Process Contingency (Using cont. listed)			$5,426	
Project Contingency,	15	% Proc Plt & Gen Plt Fac		$56,429
		Total Plant Cost (TPC)		$475,670
Plant Construction Period,	4.0	Years (1 or more)		
Construction Interest Rate,	11.2	%		
Adjustment for Interest and Inflation				$59,711
		Total Plant Investment (TPI)		$535,380
Prepaid Royalties				$1,881
Initial Catalyst and Chemical Inventory				$262
Startup Costs				$13,074
Spare Parts				$2,378
Working Capital			$6,953	
Land, 200 Acres				$1,300
		Total Capital Requirement (TCR)		$561,229
		$/kW		1370

ANNUAL OPERATING COSTS – CASE 3

Capacity Factor =	85	%			
			UNIT $		ANNUAL
COST ITEM	QUANTITY		PRICE		COST, K$
Coal (Illinois #6)	3,089	T/D	$29.40	/T	$28,178
Consumable Materials					
Water	1,482	T/D	$0.19	/T	$87
HGCU Sorbent	0.09	T/D	$6,000	/T	$167
Nahcolite	3.0	T/D	$275	/T	$256
Ash/Sorbent Disposal Costs	427	T/D	$8.00	/T	$1,061
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,592
Maintenance Costs	2.2%				$10,465
Royalties					$282
Other Operating Costs					$864
	Total Operating Costs				$48,407
By-Product Credits					
Sulfuric Acid	236.1	T/D	$68.00	/T	$4,981
____________________	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				$4,981
	Net Operating Costs				$43,426

BASES AND ASSUMPTIONS – CASE 3

A. CAPITAL BASES AND DETAILS

		QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory						
Water		37785	T	$0.19	/T	$7
HGCU Sorbent		39	T	$6,000	/T	$234
Nahcolite		77	T	$275	/T	$21
	Total Catalyst and Chemical Inventory					$262
Startup costs						
Plant modifications,	2	% TPI				$10,708
Operating costs						$1,685
Fuel						$681
		Total Startup Costs				$13,074
Working capital						
Fuel & Consumables inv	60	days supply				$5,548
By-Product inventory	30	days supply				$482
Direct expenses	30	days				$923
		Total Working Capital				$6,953

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

	% 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 3

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	10.1	8.8
Consumables	0.6	0.5
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-1.9	-1.6
Total Cost of Electricity	48.8	41.1

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 Quench	Texaco Radiant +	Convective	Shell		Destec		British Gas/ 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 Oxygen Blown		Transport Air-Blown		Transport Oxygen-Blown	
	With	/out In-Bed Sulf Captur							
	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 Quench CGCU CASE 1	Texaco Radiant + Convective CGCU CASE 2	Texaco Radiant + Convective HGCU CASE 3	Shell CGCU CASE 1	Shell HGCU CASE 2	Destec CGCU CASE 1	Destec HGCU CASE 2	British Gas/ Lurgi CGCU CASE 1	British Gas/ Lurgi HGCU 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 With HGCU CASE 1	KRW Air-Blown /out In-Bed Sulf Captur CGCU CASE 2	KRW Air-Blown /out In-Bed Sulf Captur HGCU CASE 3	KRW Oxygen Blown CGCU	KRW Oxygen Blown HGCU	Transport Air-Blown CGCU	Transport Air-Blown HGCU CASE 1	Transport Oxygen-Blown CGCU	Transport Oxygen-Blown HGCU 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

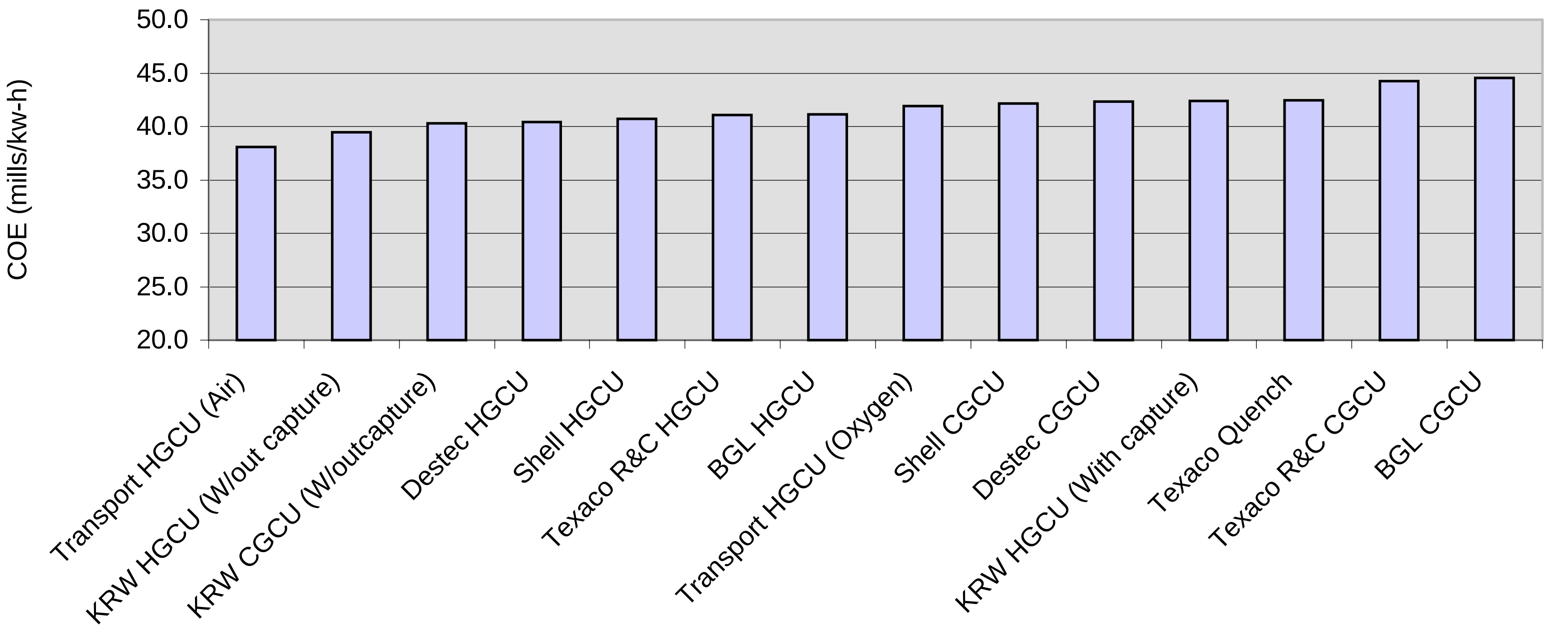
COE Summary IGCC Systems Study 2000 Update

Transport HGCU (Air)	38.1
KRW HGCU (W/out capture)	39.5
KRW CGCU (W/outcapture)	40.3
Destec HGCU	40.4
Shell HGCU	40.7
Texaco R&C HGCU	41.1
BGL HGCU	41.1
Transport HGCU (Oxygen)	41.9
Shell CGCU	42.1
Destec CGCU	42.3
KRW HGCU (With capture)	42.4
Texaco Quench	42.5
Texaco R&C CGCU	44.3
BGL CGCU	44.5

COE Summary IGCC Systems Study 1998

Transport HGCU (Air)	43.6
KRW CGCU (W/outcapture)	46.1
Destec CGCU	46.2
Destec HGCU	47.0
Texaco Quench	47.2
Shell CGCU	47.9
KRW HGCU (W/out capture)	48.0
Shell HGCU	48.0
Texaco R&C CGCU	48.1
KRW HGCU (With capture)	48.3
Transport HGCU (Oxygen)	48.4
BGL HGCU	48.5
Texaco R&C HGCU	48.8
BGL CGCU	50.3

IGCC Base Case COE Comparison



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