4. ECONOMIC EVALUATION OF SSRP

4.1. Introduction

Over the past three years RTI has been investigating the Single-step Sulfur Recovery Process (SSRP). The SSRP (Figure 3.1) is an alternative to the conventional amine-Claus-SCOT process in which H_2S is removed from syngas and converted to elemental sulfur. In the SSRP, H_2S laden syngas is mixed with a quantity of SO_2 containing gas such that the ratio of H_2S to SO_2 in the syngas is 2.0. This mixture is then passed to a slurry bubble column reactor (SBCR) where the gas is contacted with a slurry of SSRP catalyst in liquid sulfur at about 300°F and at near the gasification pressure. In the SBCR, the H_2S and SO_2 react via the Claus reaction and produce liquid elemental sulfur. An amount of sulfur equivalent to the yield of sulfur produced by the Claus reaction is withdrawn from the SBCR. Approximately 1/3 of this yield is burned with air to produce the SO_2 that is mixed with the untreated syngas prior to passage into the SBCR. The remaining 2/3 of the elemental sulfur is product which can be sold. Experiments carried out at RTI which simulate the SSRP, have shown that it is possible to remove 99% of the inlet sulfur passed to the catalytic reactor. About 1% of the sulfur as SO_2, H_2S and a small fraction as COS remain in the treated syngas. Thus in a single catalytic reactor supported by an external sulfur burner, the SSRP accomplishes the same job as the amine-Claus-SCOT which involves numerous columns and catalytic reactors. This observation indicates that the SSRP may be a cost effective alternative to the amine-based scrubbing process and can potentially make power generation by IGCC less capital intensive.

An economic evaluation of the SSRP as applied to IGCC power generation was carried out and compared to a cost analysis carried out by EG&G (*Shelton and Lyons, 1998*) for IGCC power generation using a Texaco gasifier and an amine-Claus-SCOT process for sulfur control. DOE's objective in sponsoring this work at EG&G was "to establish base cases for commercially available (or nearly available) power systems having a nominal size of 400 megawatts (MWe)." Thus it is an excellent analysis upon which to base an economic evaluation of the SSRP and can also serve as a source of economic evaluations of IGCC processes using various sulfur control technologies to which IGCC - SSRP can be compared.

4.2. Selection of IGCC Base Case

In the EG&G Report, three base cases are presented. For each case, fairly detailed material and heat balances are presented. In addition capital and operating cost are computed for each base case. The three cases are summarized in Table 4.1. The major differences between the three base cases are the mode of gas cooling following the Texaco gasifier and the gas cleanup systems. In Case 1 the gasifier is operated at a pressure of 615 psia with raw gas cooling being accomplished by quenching the raw gas with liquid water. The quenched and partially cooled syngas is then passed through a COS hydrolysis unit to convert COS to H_2S. H_2S is removed by first cooling the syngas to 103°F, and then scrubbing it with MDEA to remove approximately 99% of H_2S from syngas. The MDEA scrubbing unit is supported by Claus and SCOT units to recover the absorbed H_2S as elemental sulfur.

Table 4.1. Texaco Gasifier IGCC Base Cases Summary

	CASE 1	CASE 2	CASE 3
Gasifier	Texaco	Texaco	Texaco
Gasifier Pressure, psia	615	475	475
Cooling Mode	Quench	RSC + CSC	RSC + CSC
Sulfur Removal	CGCU	CGCU	HGCU
Gas Turbine Power (MWe)	271.9	272.5	271.2
Steam Turbine Power (MWe)	154.1	192.4	184.9
Misc/Aux Power (MWe)	44.4	54.5	49.2
Total Plant Power (MWe)	381.7	410.4	406.9
Efficiency, HHV (%)	39.6	43.4	46.3
Efficiency LHV (%)	41.1	45.0	48.1
Total Capital Requirement, ($1,000)	519,625	596,033	593,871
$/KW	1,361	1,452	1,459
Net Operating Cost ($1,000)	57,128	69,832	70,836
COE (mills/kwh)	47.2	48.1	48.8

RSC: Radiant Syngas Cooler
CSC: Convective Syngas Cooler
CGCU: Cold Gas Cleanup → Amine & Claus & SCOT
HGCU: Hot Gas Cleanup → transport desulfurization

Case 2 of the EG&G Report is similar in operation to Case 1 except in Case 2 attempts are made to recover the heat of the raw gas more efficiently than Case 1 by radiant and convective cooling of the syngas to raise steam for power generation. In Case 2, H_2S is removed from the syngas as elemental sulfur via the DMEA-Claus-SCOT. In Case 3 of the EG&G Report, radiative and convective cooling of the syngas is used to raise steam for power generation. In Case 3, however, H_2S is removed from the syngas at high temperature using a solid sorbent in a circulating fast fluidized bed reactor system. The absorbed sulfur is eventually recovered as sulfuric acid.

As shown in Table 4.1, Case 1 has the lowest total capital requirements and lowest cost of electricity (COE); however, it is the least thermally efficient process of the three cases. Since RTI proposes to compare the SSRP with an amine process to remove H_2S from the syngas, Case 3, which uses a circulating solid sorbent for this purpose, is eliminated from consideration as a choice of base case against which to compare the SSRP. Because Case 1 operates at the highest process pressure of the remaining cases, RTI has chosen to use Case 1 as a basis for comparing the amine based removal of H_2S versus SSRP to remove H_2S. The elevated pressure of Case 1 more nearly matches the preferred operating pressure of the SSRP than does the operating pressure of Case 2.

4.3. Base Case 1: Texaco-IGCC-Amine

A simplified flow sheet of the Base Case 1 is shown in Figure 4.1. Illinois #6 coal is crushed and mixed with water to produce a coal / water slurry containing roughly 33% water. This slurry is pumped into the Texaco gasifier along with oxygen. The gasifier operates at about 615 psia in a down flow-entrained mode at temperatures in excess of 2300°F. The coal's sulfur is converted to mostly H_2S with some COS being formed. The raw syngas leaves the gasifier at 2300 to 2700°F along with molten ash and unburned carbon particles. This stream is then passed to a large water pool, which cools the gas and removes solidified ash particles. As shown in Fig. 4.1, the cooled raw gas enters a gas scrubbing section to remove additional fine solids before the gas is passed to the Gas Cooling Section.

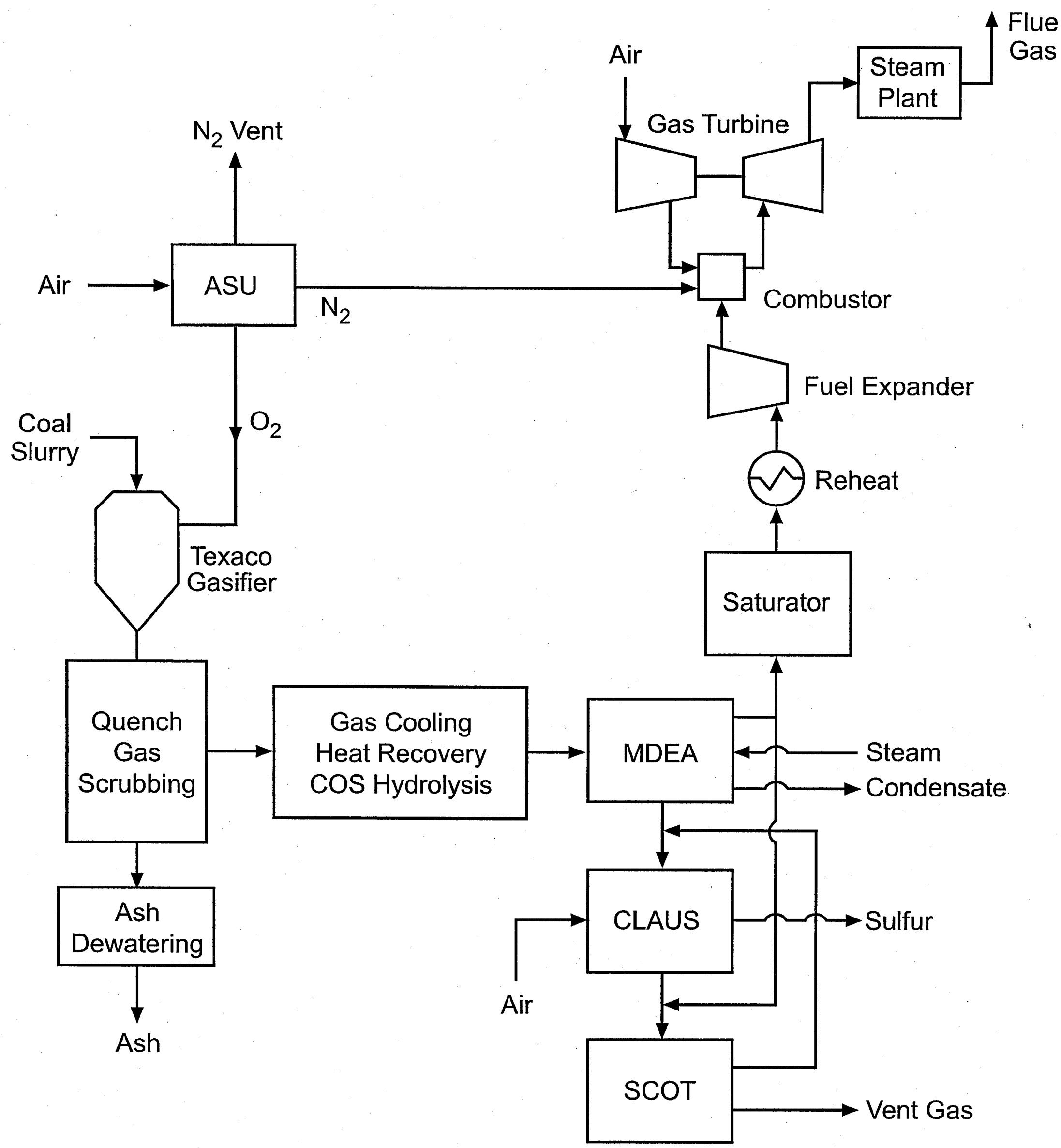

Figure 4.1. Simplified flow sheet for the Texaco-IGCC using an amine-base H_2S to elemental sulfur process

In the Gas Cooling Section the raw syngas in cooled from 425°F to 103°F in a series of heat exchangers. Heat recovered in this heat exchange network is used to generate low-pressure steam for the HRSG. Low quality heat is used for BFW heating. Condensate produced in the heat exchange is used to resaturate the clean syngas after it leaves the amine scrubber unit. The Gas Cooling Section also contains a catalytic hydrolyzer in which COS is converted to H_2S. This is necessary because COS will pass through the amine scrubber and would significantly increase the sulfur load in the cleaned syngas if COS were not converted to H_2S prior to the amine scrubber.

The MDEA/Claus/SCOT process is used for cold syngas cleanup and elemental sulfur recovery. As shown in Fig. 4.1, the cooled gas from Gas Cooling Section is passed to the MDEA absorber where it is contacted with a lean, with respect to H_2S and CO_2 content, MDEA solvent. Almost all of the H_2S and a portion of the CO_2 in the syngas are removed in the MDEA scrubber. The H_2S-rich MDEA solvent exits the absorber and is heated by H_2S lean solvent from the H_2S/MDEA stripper in a heat exchanger before entering the stripper column. Acid gases exiting the MDEA stripper are sent to the Claus/SCOT units for sulfur recovery. The lean MDEA solvent exiting the stripper column is cooled and eventually recycled to the scrubbing column. Approximately 98.5% of the cleaned syngas from the MDEA scrubber is sent to the gas turbine whereas 1.5% of the cleaned syngas is mixed with the Claus off gas prior to being fed to the SCOT tail gas treatment unit.

The Claus process is carried out in two steps. In the first stage about one-quarter of the gases from the amine stripper column are mixed with the recycle acid gases from the SCOT unit as shown in Figure 4.1 and burned in air in a furnace. The remaining acid gas from the amine stripper is mixed with this combustion gas in the second stage of the Claus process which is a sequence of catalytic reactors were H_2S and SO_2 react to form elemental sulfur. Following each catalytic reactor the gas is cooled to condense out elemental sulfur and reduce the inlet temperature of the catalytic reactor to improve the thermodynamic favorability of the Claus reaction.

The tail gas from the last Claus reactor, which contains elemental sulfur, SO_2, H_2S and COS, is sent to the SCOT unit where in the presence of the 1.5% of the cleaned syngas, as mentioned previously, SO_2 is converted to H_2S with the aid of a cobalt-molybdate catalyst. The effluent is cooled before being sent to an absorber column where H_2S is removed. The H_2S rich stream is sent to a regenerator where H_2S is released. The acid gas from the regenerator is recycled to the inlet of the Claus unit as shown in Fig. 4.1.

The portion of the clean syngas leaving the amine scrubber that is sent to the gas turbine combustor is humidified with high pressure condensate generated in the Gas Cooling Section, as shown in Fig.4.1, to increase mass flow rate through the gas turbine and the fuel expander. This humidification reduces the amount of nitrogen feed to the gas turbine from the air separation unit that is needed to fully load the gas turbine unit.

4.4. Texaco-IGCC-SSRP System

Basically the flow sheet for the Texaco-IGCC-SSRP system is the same as that for the Base Case 1 flow sheet shown in Fig.4.1 except the SSRP is inserted between the Gas Cooling Section and the Gas Saturation Unit. In the case of H_2S being removed by the SSRP, all of the treated syngas is sent to the Gas Saturator, whereas in Base Case 1, about 1.5% of the clean syngas is consumed in the SCOT unit. As a consequence of 100% of the clean syngas going to the gas turbine, and because it is assumed that the production rate of electrical power will be held constant in the comparison of the Texaco-IGCC processes using the two H_2S-to-sulfur removal options, the rate at which coal is gasified and the flow rate of raw syngas will be 1.5% less in the case of the SSRP H_2S removal process versus the amine-based process. This translates into reduced equipment and operating costs of the units upstream of the SSRP in comparison to the costs associated with the amine-based process. The methods used to evaluate these costs will be described below following a brief description of the SSRP unit.

A simplified flow sheet of the SSRP unit is shown in Figure 4.2. This may be an unduly complicated version of the SSRP, in that, fine adjustments to the ratio of H_2S to SO_2 in the inlet gas to the SBCR are made by vaporizing liquid SO_2, which is produced and stored for this purpose. The ratio of H_2S to SO_2 in the raw syngas at the inlet of the SBCR is maintained at 2.0. This is accomplished in part by liquid SO_2 as mentioned above and in large part by burning product sulfur in air to produce SO_2 as shown in Fig. 4.2. The raw fuel gas enters the SBCR at approximate 260°F and 600 psia and is saturated with water vapor. A small amount of supplemental steam and/or saturated liquid water can be supplied to the SBCR as needed to control the slurry temperature at approximately 300°F (150°C) and the water vapor content at 10%. In the SBCR, the raw gas with a H_2S to SO_2 ratio of 2.0 is contacted with a slurry of liquid elemental sulfur and a catalyst, which has been shown by RTI to promote the Claus reaction in the presence of liquid sulfur. Approximately 99% of the H_2S and SO_2 entering the SBCR will be converted to elemental sulfur. As mentioned above, the gas from the Gas Cooling Section is passed to the SBCR at 260°F (127°C). Thus the Gas Cooling Section will require less heat exchange equipment than the Gas Cooling Section associated with using the amine-based unit for H_2S removal. In calculating the capital cost of the Gas Cooling Section associated with the use of the SSRP unit to remove sulfur the decrease in the exchange surface area was not taken into consideration. The cost of the Gas Cooling Section was based simply on the total syngas throughput of the Gas Cooling Section as will be described below. Thus the capital cost of Gas Cooling Section associated with the use of the SSRP will be highly conservative.

The Gas Cooling Section also contains a COS hydrolysis reactor due to the fact that COS will pass through the amine scrubber. For the Gas Cooling Section associated with the use of the SSRP this catalytic reactor may not be necessary in that the SSRP may be able to convert COS to elemental sulfur in the SBCR by adding a COS hydrolysis functionality to the SSRP catalyst or by admixing hydrolysis catalyst with the SSRP catalyst in the SBCR catalyst slurry. The fate of COS in the SSRP will be one of the subjects of the future research on the SSRP.

As shown in Fig. 4.2, liquid sulfur is withdrawn from the SBCR and passed through a filter to separate the SSRP catalyst from the liquid sulfur. The separated SSRP catalyst is returned to the SBCR. Also, the sulfur product is withdrawn after the filter. The SSRP catalyst is assigned a highly conservative active life of about 6 months.

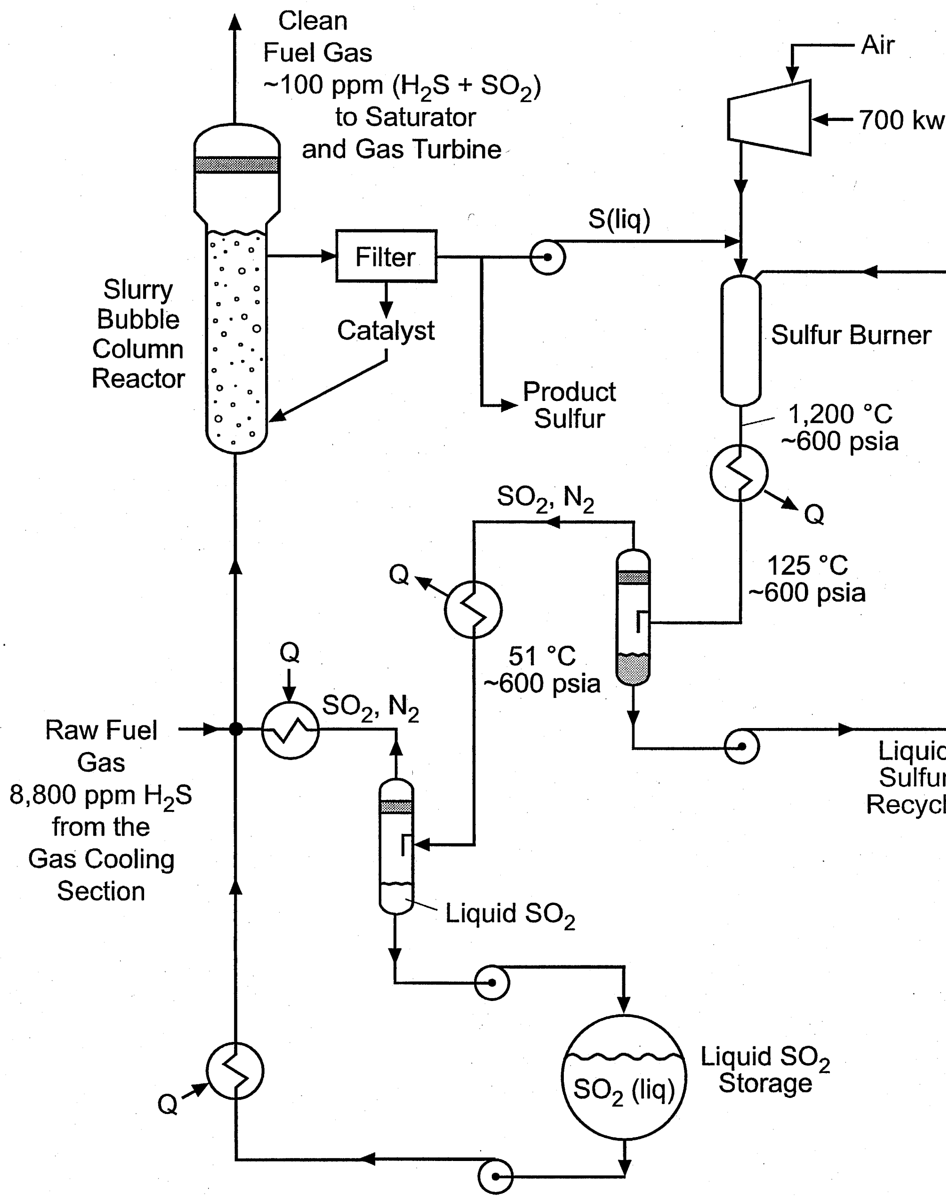

Figure 4.2. Simplified SSRP flowsheet

About 1/3 of the sulfur produced in the SBCR will be burned with a stoichiometric amount of air at approximately 600 psia. The sulfur burner is anticipated to be spray-type burner. Liquid sulfur in excess of the amount burned will be sprayed into the burner to help control the temperature at 1200°C (2200°F). The vaporized sulfur, sulfur dioxide and nitrogen produced in the sulfur burner will be cooled to approximately 125°C (257°F) and the SO_2 and N_2 will be separated from the unreacted liquid sulfur as shown in Fig.4.2. The condensed sulfur will be recycled to the burner. The SO_2/N_2 mixture will be further cooled to about 50°C (122°F) to partially condense SO_2. The condensed SO_2 will be stored and used intermittently by quickly adjust the H_2S/SO_2 ratio in the inlet of the SBCR to 2.0.

While the SSRP flow sheet shown in Fig.4.2 is complex, most of the complexity can be attributed to maintaining a ratio of H_2S to SO_2 of 2.0 in the inlet of the SBCR. The complexity of this support equipment could be sealed back by not accumulating liquid SO_2 as shown in Fig.4.2 and simply adjusting the flow of oxygen to the burner to give the proper flow of gaseous SO_2 in the SO_2/N_2 mixture so that the ratio of H_2S to SO_2 in the inlet of the SBCR is 2.0. The flow sheet for the SSRP shown in Fig.4.2 is complex; but the complexity pales in comparison to the DMEA-Claus-SCOT process. The SSRP eliminates numerous catalytic reactors, inter-stage cooling exchangers and separation devices.

4.5. Comparison of Base Case 1 with SSRP

In comparing the Texaco-IGCC power generation system using the amine based processes for removing H_2S from syngas to produce elemental sulfur with the SSRP to do the same job, the two H_2S removal alternatives must be compared in the context of being part of the Texaco-IGCC process. The reason for this is that the amine-Claus-SCOT process consumes about 1.5% of the syngas, which is then not available for power production whereas the SSRP does not consume syngas and the full production of syngas is available for power generation. Thus the Texaco-IGCC using the SSRP can generate the same level of electrical power as the Texaco-IGCC using amine-based H_2S removal using smaller, less expensive gasifier and gas cooling equipment and fewer resources, such as highly purified oxygen and coal. These savings associated with the use of the SSRP will then allow more to be spent on the SSRP than the amine-based process and have the same COE, or as will be shown in the discussion below, a reasonably priced SSRP unit will yield a significantly reduced COE for the Texaco-IGCC than a Texaco-IGCC process using amine-based H_2S removal.

Two basic approaches can be taken. One, the amount of coal used in the gasifier could be held constant in the two alternatives. Thus, because the SSRP des not consume valuable fuel gas, whereas the DMEA-Claus-SCOT process consumes 1.5% of the clean syngas, the SSRP can generate about 1.5% more electrical power than the system that uses the DMEA-Claus-SCOT for H_2S removal from the syngas and elemental sulfur production. Given the scenario of similar coal feed rates for the two alternatives then the amount of capital and operating expenses available for the SSRP that would give the same COE as the Base Case 1 could be computed. The estimated capital and operating expenses of the SSRP could then be compared to the permissible, COE breakeven capital and operating expense to determine if the SSRP is competitive with the amine-based option.

Another way of comparing the two H_2S removal options and the one used by RTI was to hold the amount of power generated constant and adjust the amount of coal that was fed to the Texaco-IGCC to generate the same level of power as the Base Case 1. The permissible levels of capital and operating expenses that could be utilized in the SSRP to give the same COE as Base Case 1 was calculated and compared to estimates for the SSRP in order to determine if the SSRP would be economically competitive with the amine based H_2S removal process.

For the Texaco-IGCC-Amine based power generation system, Base Case 1, the capital requirements and annual operating costs are shown in Tables 2 and 3, respectively.

Table 4.2. Installed costs of equipment and total capital requirement for the Texaco-IGCC using two alternative H_2S removal processes

Plant Section	Texaco-IGCC with Amine H_2S Removal			Texaco-IGCC with SSRP H_2S Removal		
	Process Cont, %	Process Cont, k$	1Q 1997 Cost, k$ w/o Cont	Process Cont %	Process Cont, k$	1Q 1997 Cost, k$ w/o Cont
Coal Slurry Preparation	0	$0	$27,191	0	$0	$26,911
Oxygen Plant	0	$0	$67,357	0	$0	$66,821
Texaco Gasifier (Quench)	15	$3,605	$24,032	15	$3,572	$23,815
Low Temperature Gas Cooling/Gas Saturation	0	$0	$17,237	0	$0	$17,061
MDEA	0	$0	$5,313	0	$0	$0
Claus	0	$0	$9,968	0	$0	$0
SCOT	0	$0	$4,216	0	$0	$0
SSRP	0	$0	$0	50	$2,650	$5,300
Gas Turbine System	10	$5,400	$53,996	10	$5,400	$53,996
HRSG/Steam Turbine	0	$0	$45,211	0	$0	$45,211
	Subtotal, Installed Equipment Cost		**$245,521**			**$239,115**
Bulk Plant Items						
Water Systems	0	$0	$18,071	0	$0	$16,977
Civil/Structural/Architectural	0	$0	$23,416	0	$0	$21,999
Piping	0	$0	$18,0712	0	$0	$16,977
Control/Instrumentation	0	$0	$6,618	0	$0	$6,217
Electrical	0	$0	$20,362	0	$0	$19,129
	Subtotal, Process Plant Cost		**$341,059**			**$320,414**
Engineering Fees			$34,106			$32,041
Process Contingency (Using Process contingency listed above)			$9,004			$11,622
Project Contingency, 15% Process Plant Cost			$51,159			$48,062
	Total Plant Cost (TPC)		**$435,329**			**$412,139**
Plant Construction Period, 4.0 Years (1 or more)						
Construction Interest Rate, 12.7%						
Adjustment for Interest and Inflation			$57,551			$54,485
	Total Plant Investment		**$492,879**			**$466,624**
Prepaid Royalties			$1,705			$1,602
Initial Catalyst and Chemical Inventory			$76			$75
Startup Costs			$13,693			$13,009
Spare Parts			$2,177			$2,061
Working Capital			$7,794			$7,634
Land, 200 Acres			$1,300			$1,300
	Total Capital Requirement (TCR)		**$519,625**			**$492,305**
	$/kW		1361			1290

Table 4.3. Annual operating costs for the Texaco-IGCC using two alternative H_2S removal processes

Cost Item	Unit $ Price	Texaco-IGCC with Amine H_2S Removal: Quantity	Texaco-IGCC with Amine H_2S Removal: Annual Cost, k$	Texaco-IGCC with SSRP H_2S Removal: Quantity	Texaco-IGCC with SSRP H_2S Removal: Annual Cost, k$
Coal (Illinois #6)	$30.60 /T	3,385 T/D	$32,136	3,334 T/D	$31,654
Consumable Materials					
Water	$0.19 /T	4,333 T/D	$255	4,268	$252
MDEA Solvent	$1.45 /Lb	403.2 Lb/D	$181	0	0
Claus Catalyst	$470	0.01 T/D	$1	0	0
SCOT Activated Alumina	$0.67 /Lb	15.9 Lb/D	$3	0	0
SCOT Cobalt Catalyst			$5	0	0
SCOT Chemicals			$16	0	0
SSRP Catalysis	$470 /T	0	$0	0.4 T/D	$58
Ash/Sorbent Disposal Costs	$8.00/T	634 T/D	$1,574	625 T/D	$1,551
Plant Labor					
Oper Labor (incl benef)	$34.00 /Hr.	22 Men/shift	$6,535	22 Men/shift	$6,552
Supervision & Clerical			$3,684		$3,598
Maintenance Costs 3.3%			$14,366		$13,601
Insurance & Local Taxes			$8,707		$8,243
Royalties			$321		$317
Other Operating Costs			$1,228		$1,199
	Total Operating Costs		**$69,014**		**$67,025**
By-Product Credits					
Sulfur	$75.00 /T	81.0 T/D	$1,886	79.1 T/D	$1,841
	Total By-Product Credits		**$1,886**		**$1,841**
	Net Operating Costs		$67,128		$65,184

Capacity Factor = 85%

These cost figures are those that were summarized in the EG&G Report. The corresponding cost figures derived by RTI for the Texaco-IGCC-SSRP are also shown in Tables 4.2 and 4.3. The derivation of these costs will be described below.

4.6. Cost Calculation Details

In the case where the SSRP is used to remove H_2S from the raw syngas and the level of power generation is the same for the two alternative H_2S removal processes presently under consideration, the capacity of the equipment upstream of the SSRP unit will be 1.5% less than the capacity of the equipment needed to support the same level of power generation while utilizing the amine based H_2S removal unit. Thus the installed cost of the Coal Slurry Preparation, Oxygen Plant, Texaco Gasifier and the Gas Cooling Section of the process as summarized in Table 2 where computed by the methods listed at upper portion of Table 4.4. Basically it was assumed that the installed cost-capacity relation was given in the form:

$$\left[\text{Installed Cost of Equipment i}\right] = A_i\left[\text{Capacity of Equipment i}\right]^{n_i} \qquad (4.2)$$

where A_i and n_i are constants unique to equipment i.

For the Coal Slurry Preparation and Oxygen Plant units the capacity exponents $\mathbf{n_i}$ shown in Table 4.4 were determined by the least square fit of the cost/capacity data in the form given by Equation 4.2 for the three cases given in the EG&G Report. This could not be done for the Texaco gasifier quench unit and the Gas Cooling Section due to the radically different nature of these units in the three base cases discussed in the EG&G Report. Therefore the exponent in Equation 4.2 and as shown in Table 4.4 for the Texaco gasifier/quench unit was assumed to be n=0.6 which is a rule of thumb exponent that is often assumed in the absence of hard cost/capacity data. The Texaco gasifier used in the EG&G Report had a nominal capacity of 3,000 tons of coal per day. One might ponder then why the variation of capacity of 1.5% would even be a consideration in the cost of the gasifier since surely there must be turn-up or turn-down capacity built into the nominal capacity of the Texaco gasifier. The reason the small variation in gasifier capacity on the cost of the gasifier/quench unit was even considered, is based on analogy to how DOE handled the small changes in capacity of the gas turbine for the three base cases in the EG&G Report. Here, all three cases utilized the W501G gas turbine, which would be expected to have some turn- down or –up capacity, yet variation in the cost of the turbine was considered even for minute changes in capacity among the three base cases.

For the Gas Cooling Section the exponent in Equation 4.2 and as shown in Table 4.4 was assumed to be n=0.68, which is the figure suggested by *Garrett (1989)* for heat exchange equipment. Using the cost scaling formula shown in Table 4.4 the Gas Cooling Sections should yield highly conservative cost estimates for the Gas Cooling Section for the SSRP based IGCC in that the raw gas needs to be cooled only to 260°F rather than 103°F for the process using the amine-based H_2S removal unit. The cost savings due to the higher allowable inlet temperature for the SSRP was not determined due to scant details and the black box nature of the Gas cooling Section given in the EG&G Report.

Table 4.4. Details of Costing Plant Sections and Bulk Plant Items

Costing of Plant Sections	
Coal Surry Preparation	$Cost2=Cost1\cdot(Capacity2/Capacity1)^{0.6844}$
Oxygen Plant	$Cost2=Cost1\cdot(Capacity2/Capacity1)^{0.5288}$
Texaco Gasifier	$Cost2=Cost1\cdot(Capacity2/Capacity1)^{0.6}$
Low Temperature gas cooling and Gas Saturation	$Cost2=Cost1\cdot(Capacity2/Capacity1)^{0.68}$
Gas Turbine Section	Same as Case 1 of The EG&G Report
HRSG/Steam Turbine Section	Same as Case 1 of the EG&G Report
Costing of Bulk Plant Items	
Bulk Plant Item	% of Installed Equipment Cost
Water Systems	7.1
Civil/Structural/Architectural	9.2
Piping	7.1
Control and Instrumentation	2.6
Electrical Systems	8.0
Total	**34.0**

The installed cost of the SSRP unit shown in Table 4.2 is based on the observation that the SSRP basically consists of a single high pressure scrubber-like column such as might be used for the DMEA scrubber of Case 1. While the SSRP has other minor supporting equipment, such as the sulfur burner, these are well developed and should add a minimum of cost. Therefore, the installed cost of the SSRP was assumed to be approximately the cost of the DMEA unit of Case 1 even though the cost of the DMEA unit includes the cost of two large column: the amine scrubbing and stripping columns. This qualitative cost of the SSRP was used due to the fact that the engineering details of SBCR have not been researched as of yet. For example the sizing of the SBCR in the SSRP is highly dependent on the solubility of SO_2 and H_2S in liquid sulfur; however, nothing is known of these solubilities. What is known though is that 99% conversion of the H_2S and SO_2 entering the SSRP can be achieved at quite reasonable space velocities. Due to the uncertainly of the sizing of the SBCR in the SSRP and consequently the installed cost of the SSRP as shown in Table 4.2, RTI has assigned a large process contingency to the SSRP unit of 50%.

As stated above the generating capacity of the gas turbine and steam turbines have been assumed the same for the Texaco-IGCC using either the amine-base H_2S removal or the SSRP. Thus the installed costs of these power generators are the same for the two H_2S removal alternatives as shown in Table 4.2.

The method of costing of the bulk plant items is also shown in Table 4.4. These are based on set percentages of the installed equipment cost as prescribed by DOE. Other factors that contribute to the total capital requirement as listed in Table 4.2 are shown in Table 4.5. These cost factors, like the bulk plants items are based on set percentages of the Process Plant Cost (PPC), Total Plant Cost (TPC), and the Total Plant Investment (TPI). In Table 4.5 listed under Start-up costs is a category labeled "Operating Costs." This cost is not explicitly defined in the text of the EG&G Report and therefore for the purposes comparing in Table 4.2 the capital requirements for the Texaco-IGCC using either amine based H_2S removal or SSRP the following estimate was used to determine the operating cost category of the Start-up Costs.

Start-up Costs

$$\text{Operating Cost} = \frac{\text{Total Operating Cost - Coal Cost}}{365} \times 30 \tag{4.3}$$

A second cost item listed in Table 4.2 that is insufficiently defined in the EG&G Report to calculate is the Working Capital. Working Capital is divided into three costs as shown in Table 4.5. Two of the three costs are straight forward; however, the third "Direct Expenses" is not defined in any manner in the EG&G Report and was calculated for the SSRP-based case by the using assuming the fraction of Direct Expense of the Net Operating Cost were similar for the Texaco-IGCC using the two alternative H_2S removal process. Thus,

Working Capital

$$\text{Direct Expenses (SSRP)} = \text{Direct Expenses (DMEA)} \times \frac{\text{Net Operating Cost (SSRP)}}{\text{Net Operating Cost (DMEA)}} \tag{4.4}$$

The third cost item listed in Table 4.2 that was not explicitly defined in the EG&G Report was the Adjustment for Interest and Inflation (AII). This cost as applied to the SSRP case was assumed to be the same fraction of the Total Plant Cost (TPC) as that for the Base Case 1, the amine-based H_2S removal process. Thus,

Adjustment for Interest and Inflation (AII)

$$\text{AII (SSRP)} = \text{AII (DMEA)} \times \frac{\text{TPC (SSRP)}}{\text{TPC (DMEA)}} \tag{4.5}$$

Based on the cost calculations listed in Tables 4.4 and 4.5 and suing Equations 4.3 through 4.5, the Total Capital Requirement (TCR) for the Texaco-IGCC with the SSRP H_2S removal option can be calculated as shown in Table 4.2. Examination of Table 4.2 shows that the TCR for the two alternative processes are \$1,361/kw and \$1,290/kw for the amine and SSRP H_2S removal options, respectively. Thus the SSRP option gives over a 5% reduction in TCR over the amine option.

Table 4.5. Capital Cost Assumptions

General Facilities	0
Engineering Fee	10% of PPC
Project Contingency	15% of PPC
Construction Period	4 Years
Inflation Rate	4%
Discount Rate	12.7
Prepaid Royalties	0.5% of PPC
Catalyst and Chemical Inventory	30 Days
Spare Parts	0.5% of TPC**
Land	200 Acres@ $6,500/Acre
Start-Up Costs	
Plant Modifications	2% of TPI***
Operating Costs	30 Days
Fuel Costs	7.5 Days
Working Capital	
Coal	60 Days
By-Product Inventory	30 Days
Direct Expenses	30 Days

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

In order to determine the effect of the two H_2S removal options on the Cost of Electricity (COE), the annual operating cost must be determined for the two options. Once the annual operating costs are determined they can be combined with the Total Capital Requirement (TCR) given in Table 4.2 to yield the Cost of Electricity.

The annual operating cost for the Texaco-IGCC using amine-based H_2S removal (Base Case 1) has been reported previously in Table 4.3. On the right-hand side of this table the operating costs associated with the SSRP option are also reported. The method of calculating each operating cost item listed in Table 4.3 is outlined in Table 4.6. Examination of Table 4.3 shows that the SSRP H_2S removal option reduces the net operating costs by about $2 million/yr or about 3% over the DMEA-Claus-SCOT H_2S removal option.

4.7. Calculation of the Cost of Electricity (COE)

The EG&G Report on the Texaco-IGCC base cases does not explicitly describe the accounting procedures by which the Cost of Electricity is calculated; however sensitivity analysis of the COE to increments in the Net Operating Costs and Total Capital Requirement carried out by DOE shows that COE is consistent with the following functional relationship:

Table 4.6. Operating and Maintenance Assumptions

Consumable Material Prices	
Illinois #6 Coal	\$30.60/Ton
Raw Water	\$0.19/Ton
MDEA Solvent	\$1.45/Lb
Claus Catalyst	\$470/Ton
SCOT Activated Alumina	\$0.067/Lb
SSRP Catalyst	\$470/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	3.3% of TPC
Maintenance Labor	40% Maintenance Cost
Insurance and Local Taxes	2% of TPC
Miscellaneous Operating Costs	10% of O&M Labor
Capacity Factor	85%

$$COE = \left[\frac{NOC \times 10^3}{P \times 365 \times 0.85 \times 24}\right] + B\left[\frac{TCR \times 10^3}{P \times 365 \times 0.85 \times 24}\right] \qquad (4.6)$$

where: COE is the Cost of Electricity, mils/kWh,
NOC is the Net Operating Cost, \$/yr
TCR is the Total Capital Requirement, \$,
P is the Power produced by the Plant, kW,
and B is the constant which depends on accounting procedure, interest rates, etc., hr^{-1}.

The denominator of each term of the right-hand side of the Equation 4.6 represents the kWh of power produced per year by the Texaco-IGCC process. The EG&G Report on the Texaco-IGCC base cases lists the Cost of Electricity as well as the Total Capital Requirement and Net Operating Costs for each of the three base cases. This information is reproduced in Table 4.1 of this report. Using the data in Table 4.1 to obtain at least square fit of the data in the form of Equation 4.6 yields

$$B = 0.1304\ hr^{-1} \qquad (4.7)$$

Applying Equation 4.6 and 4.7 to the TCR and NOC shown in Tables 4.2 and 4.3 shows that the cost of Electricity for the SSRP H_2S removal option is

$$COE_{SSRP} = 45.5\ mils/kWh \qquad (4.8)$$

The Cost of Electricity for the DMEA-Claus-SCOT H_2S removal option (Case 1) as shown in Table 4.1 is

$$COE_{Amine} = 47.2 \text{ mils/kWh} \tag{4.9}$$

Thus the SSRP option will reduce the Cost of Electricity by 3.6%, a significant saving.

4.8. COE Sensitivity Analysis

The COE of 45.5 mils/kWh for the SSRP option is highly dependent on the installed cost of the SSRP unit and the process contingency assigned to the unit. While every effort was made to assign reasonable installed costs and process contingency to the SSRP, it is informative to calculate the installed cost of the SSRP that might be assumed and yield the same COE as the amine based option, and see how the installed cost of $5,300,000 used in the calculation of the entrees of Tables 2 and 3 compares to this COE breakeven installed cost of the SSRP.

To calculate COE breakeven cost of the SSRP, the Total Capital Requirement as computed in Table 2 can be computed for the Texaco-IGCC-SSRP system in terms of an unknown SSRP Installed cost given by IC and yet to be prescribed Fractional Process Contingency, FPC, for the SSRP. If the cost computations indicated in Table 4.2 are carried out the following result is obtained:

$$TCR = 478826 + (1.9593 + 1.1657{*}FPC){*}IC \tag{4.10}$$

where: TCR is the Total Capital Requirement, K$,
FPC is the Fractional Process Contingency for the SSRP, dimensionless,
and IC is the Installed Cost of the SSRP, K$

Similarly if the operating cost calculations indicated in Table 4.3 are carried out the following is obtained:

$$NOC = 64452 + OX + (0.0976 + 0.0583 * FPC){*}IC \tag{4.11}$$

where NOC is the Net Operating Cost, K$/yr,
and OX is the Operating expenses of the SSRP unit, K$/yr,

Letting LP represent the mechanical and/or electrical power consumed by the SSRP, substituting Equations 4.10 and 4.11 into Equation 4.6 and setting the Cost of Electricity, COE, equal to the COE for the amine based Texaco-IGCC process of 47.2 mils/kWh gives, after simplification:

$$IC = \frac{21246 - 2.83 * OX - LP}{1 + 0.6 * FPC} \tag{4.12}$$

where IC is Installed Cost, K$, of the SSRP that will yield a COE for the Texaco-IGCC equal to the COE for the Texaco-IGCC-Amine process,
OX is Operating Costs for the SSRP, K$/yr

LP is the Mechanical and/or Electrical Power consumed by the SSRP, kW

For the Texaco-IGCC-SSRP case considered in Tables 4.2 and 4.3

OX = \$58k/yr
LP = 700kW
and FPC = 0.5.

Substituting these values into Equation 4.12 gives

IC = \$15,760k

Thus the estimated Installed Cost of the SSRP unit is roughly

$$\frac{5300}{15760} \text{ or one-third}$$

the maximum Installed Cost that could be spent on the SSRP unit and still give an estimated Cost of Electricity for the Texaco-IGCC-SSRP equal to the Texaco-IGCC-Amine process.

4.9. Summary

An economic comparison of using the DMEA-Claus-SCOT process or the SSRP to remove H_2S and convert it to elemental sulfur for the Texaco-IGCC has been made. The procedures used to calculate the Total Capital Requirement and Net Operating Cost for the Texaco-IGCC using the two H_2S removal alternatives were as prescribed by the EG&G Report on the Texaco-IGCC base cases or in the absence of explicit procedures, the costs were estimated.

The installed cost of the SSRP was estimated based on engineering judgment to be about the cost of the DMEA unit alone. Unlike the DMEA-Claus-SCOT H_2S removal unit the SSRP does not require the consumption of syngas; and therefore, if the net power generated by the Texaco-IGCC using the two alternatives is assumed to be the same, the units upstream of the SSRP will process 1.5% less material than the Texaco-IGCC process using the DMEA-Claus-SCOT H_2S removal process. The Total Capital Requirement and Net Annual Operating Costs for the two alternative processes are summarized in Table 4.2 and 4.3, respectively.

The total Capital Requirement for the IGCC process using the SSRP alternative is thought to be conservative due to the fact that the raw syngas only needs to be cooled to 260°F rather than 103°F in the case of the amine-based H_2S removal alternative and due to the lack of details of Gas Cooling Unit this difference could not be taken into consideration. Also the COS hydrolysis unit necessary in the amine-based H_2S removal process may not be needed in the SSRP, but this conjecture needs to be researched.

A summary of the economic calculations performed and described above is given in Table 4.7. It can be seen that the use of the SSRP gives significant reductions in the Total Capital Requirement, Net Operating Costs and Costs of Electricity over the three base cases. The use of the SSRP also improves the thermal efficiency of the over all Texaco-IGCC process over the efficiency of Base Case 1.

Table 4.7. Summary of the economic comparison of the Texaco-IGCC using various raw gas cooling and H_2S removal schemes

	CASE 1	**SSRP**	**CASE 2**	**CASE 3**
Gasifier	Texaco	Texaco	Texaco	Texaco
Cooling Mode	Quench	Quench	RSC + CSC	RSC + CSC
Sulfur Removal	CGCU	SSRP	CGCU	HGCU
Total Plant Power (MWe)	381.7	381.7	410.4	406.9
Efficiency, HHV (%)	39.6	40.2	43.4	46.3
Efficiency, LHV (%)	41.1	41.7	45.0	48.1
Total Capital Requirement, ($1,000)	519,625	492,299	596,033	593,781
$/KW	1,361	1,290	1,452	1,459
Net Operating Costs ($1,000)	67,128	65,182	69,832	70,836
COE (mills/kWh)	47.2	45.5	48.1	48.8