Power from PRB – Four Conceptual IGCC Plant Designs Using the Transport Gasifier

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Abstract

This paper presents the results of four detailed system and economic studies of an Integrated Gasification Combined Cycle (IGCC) plant based on the Transport Gasifier technology.

Southern Company is developing the Transport Gasifier and related systems for commercial application in the power industry in conjunction with the U.S. Department of Energy (DOE) and Kellogg, Brown and Root, Inc. (KBR). At the engineering-scale Power Systems Development Facility (PSDF) in Wilsonville, AL, several coals have been successfully gasified in both oxygen-blown and air-blown operation of the Transport Gasifier.

To guide future tests and commercialization of the technologies at the PSDF, a series of conceptual commercial plant designs have been completed in partnership with the DOE and the Electric Power Research Institute (EPRI). Four Transport Gasifier combined cycle cases have been developed to investigate the relative costs and benefits of oxygen-blown or air-blown gasification and of stack gas or syngas cleanup. These cases are all based on a 2x1 GE7FA+e combined cycle fueled by syngas from two Transport Gasifiers using Powder River Basin (PRB) sub-bituminous coal.

The performance and cost for each case has been modeled down to the individual equipment level using PSDF test data, chemical and thermal process modeling software, power plant and process plant costing software, vendor quotes, KBR data, and historical Southern Company information. Detailed operation

and maintenance plans, reliability and maintainability models, and emissions calculations have also been developed.

Two similar studies were in progress at the time of publication that investigate carbon capture from PRB-fueled Transport Gasification systems using a conventional amine system. Results will be presented in the near future in a follow-up paper.

1.0 Introduction

1.1 The PSDF

The Power Systems Development Facility (PSDF) was established in 1995 to lead the United States' effort to develop cost-competitive and environmentally acceptable coal-based power plant technologies. This large-scale pilot facility near Wilsonville, Alabama, is focused specifically on identifying ways to reduce capital cost and increase efficiency of advanced coal-based power generation while meeting strict environmental standards.

At the PSDF, the Transport Gasifier and related systems are being developed for commercial applications by Southern Company, Kellogg, Brown and Root, Inc. (KBR), the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), and other industrial participants, currently including the Electric Power Research Institute (EPRI), Siemens Westinghouse Power Corporation, Peabody Energy, the Lignite Energy Council, and Burlington Northern Santa Fe Railway. The Transport Gasifier has been used at the PSDF to gasify several coals types ranging from lignite to bituminous in both oxygen-blown and air-blown operation with generally excellent results.

The Transport Gasifier offers many advantages over commercially available gasifiers that can lead to successful commercialization. These advantages include high carbon conversion with a variety of fuels, high sulfur capture, a small footprint with a high thermal throughput, a simple and robust mechanical design, low water consumption, and the ability to easily process high ash, high melting point coals.

1.2 The Studies

To guide future tests and commercialization of the technologies at the PSDF, a series of conceptual commercial plant designs have been completed in partnership with DOE NETL and EPRI. Four Transport Gasification combined cycle cases have been developed to investigate the relative costs and benefits of oxygen-blown or air-blown gasification and of stack gas or syngas cleanup, as shown in Table 1.

	Gasifier Oxidant	Gas Cleanup
Case 1	air	stack gas
Case 2	oxygen	stack gas
Case 3	air	syngas
Case 4	oxygen	syngas

Table 1. Four Cases using Transport Gasification

To allow the most meaningful comparisons between cases, a common design basis is used whenever possible. Major similarities include the following:

- Two Transport Gasifiers
- Low-sulfur Powder River Basin (PRB) coal, fed dry
- 2x1 GE7FA+e combined cycle with an 1800 psi/1000°F/1000°F steam cycle
- Dry ash removal from the syngas at 500 – 700°F by metal filter elements
- Selective Catalytic Reduction (SCR) in the Heat Recovery Steam Generator (HRSG) to control nitrogen oxides (NO_X)
- Greenfield site in the southeast United States

Beyond these similarities, each case is individually optimized for the best cost, performance, and emissions. This leads to differences in results that are sometimes held constant in this type of study, such as net output, emissions, and coal feed rate. Rather than use non-optimum design assumptions to force these outputs to be the same, the resulting differences of each case are allowed to reveal the relative advantages and disadvantages.

Technologies are selected for these configurations that are either commercially available or are available with commercial guarantees in the very near-term. While using developmental technologies such as warm gas cleanup, oxygen membranes, or very high temperature gas filtration would improve the results and possibly change the conclusions, using available technologies and optimizing each case individually results in four system designs that are each meaningful and pertinent to producing clean power from PRB coal today. Naturally, if other fuels were selected or other end products desired (such as liquid fuels or sequestration-ready carbon) the systems would be configured differently and the results would be different.

The performance and cost for each case has been modeled down to the individual equipment level using PSDF test data, chemical and thermal process modeling software, power plant and process plant costing software, vendor quotes, KBR data, and historical Southern Company plant construction and operating information. Detailed operation and maintenance plans, reliability and maintainability models, and emissions calculations have also been developed. These are discussed in more detail below in Section 3.0, Methodology.

The assumptions and calculations in these studies are representative of an N^{th} plant. For the configurations selected, the technologies are assumed to be mature. For example, no first-of-a-kind costs are added to the capital and no penalty is added to the availability calculations for first-of-a-kind plant startup.

Two additional studies that include carbon capture were in progress at the time of publication and will be presented in a follow-up paper in the near future. These two cases are similar to Cases 3 and 4, with the addition of carbon dioxide capture from the syngas using a conventional amine system.

2.0 System Descriptions

The four cases will be described together since there are many commonalities. Differences will be noted in the text. Each case consists of two identical gasification trains, each fueling one gas turbine. Each gas turbine exhausts into a dedicated HRSG, and the output from the two HRSGs is combined in a single steam cycle. For simplicity, a single train of equipment will be described in the text. Simplified process flow diagrams for the four cases are given in Figures 1 through 4.

2.1 Gasification

The gasification island is centered around the Transport Gasifier, which operates as a pressurized, circulating fast-fluidized bed gasifier and consists of simple refractory-lined pipe sections. The design operating temperature range is approximately 1,700 to 1,900°F, and thermal expansion is accommodated without recourse to expansion joints, which have been found problematic in high-temperature, high-pressure refractory-lined systems. The operating pressure is 404 psia for Cases 1 and 2 with stack gas cleanup and 436 psia for Cases 3 and 4, due to the pressure drops associated with syngas cleanup.

Low-sulfur PRB sub-bituminous coal, an oxidant, and steam are converted into a particulate-laden syngas in the gasifier with a carbon conversion of 97 percent. Particulate-free syngas and/or off gases are recycled to the gasifier for solids aeration. During system start-up, natural gas-fired burners heat the gasifier before solids are introduced. A startup/makeup solids feed system adds material to the gasifier when needed.

In the air-blown configurations (Cases 1 and 3, shown in Figures 1 and 3) a multi-stage, intercooled, motor-driven process air compressor supplies most of the air required by the gasifier, and the balance is extracted from the gas turbine. This arrangement has two benefits: it allows the power output of the gas turbine to be maximized at different ambient conditions by varying the relative air flow rates, and it also increases the operational flexibility of the system. The air extracted from the gas turbine compressor is cooled in the process air recuperator and then added inter-stage to the process air compressor. The combined flow is further compressed and then a small stream is diverted to convey solids to the gasifier. The rest of the air is heated in the recuperator and then sent to the gasifier. A small nitrogen plant provides purge gas to the plant.

In the oxygen-blown cases (Cases 2 and 4, shown in Figures 2 and 4) a conventional cryogenic Air Separation Unit (ASU) provides the gasifier oxidant, purge nitrogen, and off gases for the process. An air extraction is taken from the combustion turbine (CT) as in the air-blown cases and combined with air from the ASU main compressor. The major off gas stream from the ASU (mostly nitrogen) is compressed and sent to the CT to maximize output and minimize NO_X formation. The 95 percent pure oxygen from the ASU is sent to the gasifier via an intercooled multi-stage compressor. Pure nitrogen for various purges in the plant is also generated by the ASU. Since not all of the off gases from the ASU are sent to the CT, the air extraction from the CT is lower in the oxygen-blown cases than in the air-blown cases.

In the configurations that use stack gas cleanup (Cases 1 and 2), dry limestone is fed to the gasifier for in-situ sulfur capture during the gasification process. This lowers the sulfur level entering the flue gas desulfurization system, decreases ammonium bisulfate formation in the HRSG, and lowers the acid dewpoint temperature in the HRSG, allowing more heat to be recovered. However, it also increases the amount of gasification ash that must be captured, handled, and disposed.

Most of the entrained gasification ash is removed from the syngas in the disengager and cyclone and recirculated back to the gasifier. The syngas and remaining particulates are cooled in the primary syngas cooler by raising high pressure saturated steam, and then further cooled in the secondary syngas cooler by raising medium pressure saturated steam. The entrained gasification ash is then captured when the syngas passes through banks of metal filter elements at 700°F in Cases 1 and 2 and at 500°F in Cases 3 and 4. Based upon current PSDF experience, a minimum operating life of 8,000 hours is expected. A safeguard device (failsafe) is installed in each filter element to protect the gas turbine from particulate-related damage in the event of a filter element failure. In the configurations using stack gas cleanup (Cases 1 and 2), the syngas is sent directly from the syngas filter to the CT at 700°F, without further cooling.

The gasification ash consists of un-reacted carbon and coal ash, plus, in Cases 1 and 2, reacted and un-reacted limestone. It is cooled and depressurized and then sent to storage silos, from which it is removed by truck to a 5-year, dry storage landfill. Tests at the PSDF have show that the material is non-hazardous and that it can be handled like conventional coal combustion ash.

The syngas compositions leaving the gasifier in Cases 1 through 4 are given in Table 2 in volume percents.

	Case 1	Case 2	Case 3	Case 4
CH_4	2.10	2.47	2.11	2.65
CO	22.59	33.88	22.58	34.83
CO_2	6.76	14.70	6.88	14.77
H_2	11.46	30.76	11.45	29.51
HCN	0.02	0.03	0.02	0.03
H_2O	5.57	16.79	5.42	16.65
H_2S	0.01	0.06	0.06	0.12
N_2	51.34	1.03	51.32	1.18
NH_3	0.15	0.28	0.16	0.26

Table 2. Syngas Compositions Exiting the Gasifier, by Volume %

2.2 Syngas Treatment

In Cases 3 and 4, the particulate-free syngas leaving the filter elements is cooled in the syngas recuperator before it is passed through a reactor where carbonyl sulfide (COS) is hydrolyzed to hydrogen sulfide (H_2S). The catalyst for the reaction is alumina-based and is chlorine-resistant. Then the syngas is further cooled to near ambient temperature by steam cycle condensate, recovering the heat into the steam cycle. Next, mercury is removed from the syngas when it passes through a packed bed of sulfur-impregnated activated carbon. The activated carbon is expected to have an effective life of 12 to 18 months before it must be changed out due to increased pressure drop.

Next the syngas goes to the CrystaSulf® H_2S absorber, where almost all of the H_2S present in the syngas is absorbed by a proprietary mixture of organic solvents saturated with sulfur dioxide (SO_2). The SO_2 oxidizes all the absorbed H_2S to produce elemental sulfur. The proprietary chemical holds the elemental sulfur in solution until it is removed in separate vessels by crystallization and filtration. The CrystaSulf process is ideally suited for treating low-sulfur content syngas streams: it does not adsorb CO_2 and it has lower capital and operating costs than the more commonly used amine systems. The sulfur is discharged from the CrystaSulf process as a nearly-pure sulfur cake, but no byproduct credit is taken in the financial calculations. A simple flow diagram of the CrystaSulf process is shown in Figure 5, and more information on the process can be found in Reference 2. After the CrystaSulf process the clean syngas is reheated to 350°F in the syngas recuperator and then sent to the gas turbine.

The syngas composition entering the gas turbine in the four cases is given in Table 3. Note that the syngas in Cases 1 and 2 below has not undergone cleanup, but the pollutants will be removed post-combustion in the stack gas treatment system described in Section 2.5.

	Case 1	Case 2	Case 3	Case 4
CH_4	2.10	2.47	2.21	3.07
CO	22.59	33.88	23.74	42.14
CO_2	6.76	14.70	7.03	16.59
H_2	11.46	30.76	12.05	35.86
HCN	0.02	0.03	0.01	0.01
H_2O	5.57	16.79	1.02	0.90
H_2S	0.01	0.06	0.00	0.00
N_2	51.34	1.03	53.93	1.42
NH_3	0.15	0.28	0.01	0.01

Table 3. Syngas Compositions Entering the Gas Turbine, by Volume %

Sour water condenses from the syngas as it is cooled below the dewpoint before entering the CrystaSulf absorber in Cases 3 and 4. The water dissolves almost all the nitrogenous compounds, chloride, and fluoride present as well as lesser amounts of H_2S, COS, CO, and CO_2. The sour water is removed in the low temperature syngas coolers and in a knock-out drum and passed to the sour water treatment plant along with other minor sour water streams. Off gases from this conventional stripping process are recycled to the process through compressors. The ammonia is recovered as anhydrous ammonia for use in the SCR (described below) and for byproduct sales. The recycled off gases, along with additional recycle syngas taken if needed from the main syngas stream before sulfur treatment, are used for gasifier aeration; filter element back pulsing; and, in the oxygen-blown cases, coal conveying.

2.3 Combined Cycle Island

The combined cycle is built around the GE 7FA+e gas turbine, modified for operation on syngas. The modifications include replacing the standard dry low-NO_X combustor cans with flame diffusion combustors to prevent flashback and replacing the stage one turbine nozzle to accommodate the increased mass flow associated with the dilute syngas fuel.

The gas turbine is fueled by natural gas when syngas is not available, both during gasifier outages and gasifier start-up. When the gas turbine is firing natural gas, water is injected into the combustion cans to limit thermal NO_X formation. This is not necessary when firing syngas since the dilute syngas and the diluent nitrogen (in Cases 2 and 4) keep the flame temperature low.

An evaporative cooling system at the gas turbine compressor inlet is used at high ambient temperatures to cool the turbine inlet air. All other standard combined cycle auxiliary equipment such as generator cooling, lube oil pumps, and water wash systems is included.

The HRSG is a dual-pressure unit with single reheat (1,800 psia/1,000°F/1,000°F). Condensate from the steam cycle is warmed in the gasification island before it enters the cold end of the HRSG. The water is heated at low pressure and then sent to the deaerator, which is integrated with the low-pressure steam drum. Some of the water from the deaerator is pumped to medium pressure and then sent to the medium pressure steam drum in the gasification island, while the remainder of the water is pumped to high pressure and sent to the high pressure economizers in the HRSG. Most of the economized water is sent to the gasification island high pressure steam drum with the rest sent to the HRSG high pressure steam drum. Desuperheating water is taken from the high pressure and medium pressure feedwater pump outlets when needed.

Saturated steam from the gasification island high pressure steam drum is returned to the HRSG high pressure steam drum so that any entrained water can be removed by the steam drum demisters. The combined steam flow is superheated in the HRSG and then sent to the high pressure section of the steam turbine. Blowdown from the high pressure steam drums is flashed at low pressure, and the steam is sent to the deaerators and the remaining water to treatment. A portion of the cold reheat steam exiting the high pressure section is sent to the gasification island in Cases 1, 2, and 4. In Case 3, excess medium pressure steam is generated in the gasification island, so the steam flow is in the other direction. The resulting cold reheat steam in all the cases is reheated in the HRSG and then expanded in the medium pressure section of the steam turbine.

In Cases 2 and 4 low pressure steam is taken from the crossover as the steam is sent to the low pressure steam turbine and sent to the ASU. In Cases 3 and 4, low pressure steam from the same source is sent to the reboilers in the sour water treatment system. The exhaust from the low pressure turbine is condensed at 1 psia by water from a wet mechanical draft cooling tower, and then sent to the gasification island for use in process cooling. The cooling tower also supplies cooling water for other process areas as needed, such as process air compressor intercoolers, ASU, coal mill systems, limestone mill systems, and the CrystaSulf system.

The HRSG exhaust temperature is maintained at least 20°F above the acid dewpoint temperature of the flue gas in each case by selection of the HRSG steam drum pinches. A selective catalytic reduction system is installed in the HRSG to reduce NO_X emissions. In Cases 3 and 4 the anhydrous ammonia reagent used in the SCR is produced from ammonia recovered from the sour-water treatment plant.

When the gasification island is not operating and generating steam, the HRSG alone must raise all of the high pressure steam. In this mode of operation, a duct burner upstream of the HRSG evaporator section fires natural gas to boost steam flow and pressure.

2.4 Solids Handling, Preparation, and Feed Systems

The design coal is sub-bituminous PRB with an as-received higher heating value of 8,760 Btu/lb, 28 percent moisture, and 0.26 percent sulfur. The coal is delivered to the site by unit trains of bottom-dump, rapid-discharge rail cars. The unloading system will unload each train in 3 to 4 hours and consists of trestles, a below-grade receiving hopper, two belt feeders, and an unloading conveyor. A radial pedestal stacker conveyor is used to form a kidney shaped, 15-day live coal pile. There is a 30-day coal storage area adjacent to the live pile.

Coal is reclaimed from the live coal pile by in-ground, vibrating reclaim bins and directed onto the reclaim conveyor, which transports it to the coal crusher. A crushed coal conveyor then takes the coal to crushed coal silos which feed the coal drying and milling systems.

The roll mill pulverizers incorporate a flash dryer in which hot gas dries the coal to approximately 18 percent moisture. The drying gas is a mixture of air, water vapor, and nitrogen containing less than 11.3 volume percent of oxygen to meet fire code standards. The oxygen content of the drying gas entering the pulverizer is monitored and nitrogen added as necessary.

A screw conveyor feeds crushed coal from a storage silo to its dedicated pulverizer. The pulverized coal and drying gas passes up the drying column and enters a cyclone, where the majority of the coal is removed and falls into a surge bin. The dusty gas then flows to a baghouse where the coal dust is separated and discharged into the same surge bin. An induced-draft fan before the baghouse and a blower before the pulverizer drive the gas through the drying circuit.

A series of water-cooled shell-and-tube heat exchangers supplied with cooling water are used to cool the drying gas below the dewpoint to condense and knock out the moisture picked up in the pulverizer. The condensed water withdrawn from the knock-out drum is sent to the water treatment plant, since it includes coal dust transmitted through the baghouse. The cooled gas is reheated in shell-and-tube heaters using medium pressure steam and the hot gas is recirculated back to the pulverizer to dry more coal. Steam heating is preferred as it avoids the operating cost associated with fuel-fired burners and it also minimizes the amount of moisture present in the drying gas and improves drying efficiency.

The coal feed system to the gasifier consists of a surge bin that receives the prepared coal, a lock vessel, a feed vessel, and a rotary feeder with a vertical axis. The coal is transported into the gasifier by air in Cases 1 and 3 and by recycle syngas in Cases 2 and 4, both via a dilute-phase conveyor.

The Powder River Basin coal composition (by weight percent) and heat content as fed to the gasifier are as follows:

C	--	58.4
H	--	3.8
O	--	13.0
N	--	0.8
S	--	0.3
Ash	--	5.8
H_2O	--	17.9
Total	--	100.0

Higher Heating Value (HHV)	--	9,852 Btu/lb
Lower Heating Value (LHV)	--	9,305 Btu/lb

Trace components include the following, again by weight percent:

Cl	--	0.012
F	--	0.004
Hg	--	0.008

In Cases 1 and 2, coarsely crushed limestone is delivered by trucks which unload directly to a 15-day live pile. An adjacent pile is sized for 30 days of storage. Limestone reclaim, milling, and feeding are almost identical to the coal systems described above, except that nitrogen is not used in the mill system since there is no explosion risk. Air is used to convey the prepared dry limestone into the gasifier. A limestone slurry is formed with the remainder of the limestone and it is pumped to the flue gas desulfurization system.

If there is not a bed of ash in the gasifier when it first starts up, then a bed of solids is first fed to the gasifier by the startup solids feed system. Sand is purchased already dried and prepared to a top size of 500 microns for this purpose, and recovered gasifier bed material can also be used. A single feed system introduces the sand into each gasifier, consisting of a surge bin, a lock vessel, a feed vessel, and two rotary feeders. The startup solids are transported into the gasifiers using air in dilute-phase conveyors.

2.5 Stack Gas Treatment

In Cases 1 and 2, almost all of the sulfur is removed from the HRSG exit flow in the stack gas treatment system, which is based on the Chiyoda CT-121™ flue gas desulfurization process. The gas turbine exhaust leaving the HRSG is cooled and saturated in a spray chamber, and then passes through a limestone slurry which removes the sulfur, as well as most of the chlorides and fluorides in the gas. A motor-driven fan provides the pressure difference to move the stack gas through the stack gas treatment system.

3.0 Methodology

The performance calculations begin with individual gasifier heat and material balances for each case, based on test results of the Transport Gasifier at the PSDF. The gasification-related components are modeled using Aspen Plus® from AspenTech, Inc. Gas cleanup performance and costs for the CrystaSulf systems are provided by CrystaTech, Inc., based on data from their pilot plant, since the CrystaSulf technology has not yet been demonstrated at a commercial scale. (The first commercial CrystaSulf unit has been installed in Emden, Germany, and will start up in August of 2005, treating 133 million scfd of gas.) KBR provided the composition of the sour water condensed from the syngas as it is cooled and data for the sour water treatment systems in Cases 3 and 4. The combined cycle in each Case is modeled using Thermoflex from Thermoflow, Inc, with the gas turbine model calibrated with performance calculations from GE Power Systems.

Obtaining performance calculations and data from outside sources requires a significant lead time, and in many cases the system information changed after calculations were requested. When necessary, data from outside sources was adjusted or scaled to match the new process conditions or the data was used to calibrate commercial models which then generated revised calculations.

Gasification-related, solids handling, and BOP equipment are sized using Southern Company-propriety routines, by using Kbase™ software from AspenTech, or by equipment vendors. Combined cycle equipment is sized using Thermoflex or GT PRO software, both from Thermoflow, Inc. Equipment costs are determined from vendor quotes, Southern Company-proprietary databases, Kbase, or Thermoflow's PEACE.

The capital costs include equipment, labor, materials, indirect construction costs, engineering, contingencies, and land. Land is valued at $5,100 per acre. Sales tax is 5 percent and freight is 2 percent of the equipment cost. Engineering is 7 percent of the total field cost. An overall contingency factor of 10 percent is applied to the estimate. Allowance for Funds Used During Construction (AFUDC) is calculated from monthly projected expenditures using current market rates over a cash flow period of sixty months. The result is approximately 14 percent of the overnight project cost. The capital costs are reported in January 2003 dollars.

The costs are representative of an N^{th} plant, so no first-of-a-kind costs are included. Appropriate equipment sparing is included in the capital costs, such as 4 x 50% feedwater pumps and 7 x 17% coal mill systems.

The Operations and Maintenance (O&M) cost estimates for each case are developed from the component level rather than by applying rule-of-thumb factors to the overall capital cost of the plant. For each case, detailed O&M models are developed that incorporate a full listing of plant equipment along with algorithms to estimate the operating manpower and requirements for maintenance (with scheduled capital costs) and expendables. These models draw on PSDF operating experience, Southern Company's operating experience with coal- and natural gas-fired power plants, and KBR's experience from the operation of their fluid catalytic cracking units.

A Reliability, Availability, and Maintainability (RAM) analysis has been completed on Cases 1 and 2 by Southern Company using UNIRAM software from EPRI, using the full equipment lists and sparing philosophy of both cases. As both the RAM analysis and the O&M cost model start at the component level, much of the source data for reliability and repair costs is taken from general industrial sources, since most equipment used in these systems has decades of history in other applications. RAM analyses are not conducted on the remaining cases, since they would be very similar.

4.0 Results

The results of these studies are summarized below. Although emissions rates were calculated, they are not presented in this paper. The emissions will be qualitatively discussed in Section 5.0, Comparisons.

4.1 Performance

The performance of the four configurations is given in Table 4.

	Case 1	Case 2	Case 3	Case 4
Net Power Output, MW	574.1	527.8	594.8	540.0
Net Efficiency (HHV), %	42.1	41.5	41.0	41.3
Net Efficiency (LHV), %	44.6	43.9	43.4	43.7
Heat Rate (HHV), Btu/kWh	8,100	8,230	8,320	8,270
Heat Rate (LHV), Btu/kWh	7,650	7,770	7,860	7,810
Coal Feed Rate, lb/hr	532,300	497,000	566,400	511,500
Gas Turbine Output, MW	394.0	394.0	394.0	394.0
Steam Turbine Output, MW	266.6	227.6	288.3	241.0
Plant Auxiliary, MW	86.6	93.7	87.5	95.0

Table 4. Power, Efficiency, and Heat Rate

Note that in each case the syngas flow is determined by the amount necessary to fire the two gas turbines to their full output. Therefore, the coal feed rate is different in each case. Important differences in the performance of the four configurations will be discussed below in Section 5, Comparisons.

4.2 Capital Costs

The capital costs are reported in Table 5 in January, 2003, U.S. dollars.

Area Description	Case 1	Case 2	Case 3	Case 4
Indirects	250.4	259.3	252.1	261.2
Coal & Sorbent Handling	23.6	23.5	21.4	21.3
Coal & Sorbent Prep & Feed	36.0	33.7	35.6	26.7
Feedwater & Misc. BOP Systems	13.8	12.1	13.4	13.8
Gasifier & Accessories	64.9	48.5	66.0	51.5
Emissions Facilities	22.7	22.7	30.7	27.8
Gas Turbine & Accessories	60.9	60.8	60.9	60.9
HRSG & Stack	51.8	44.6	51.1	51.4
Steam Turbine & Piping	32.8	30.8	34.8	31.7
Cooling Water System	18.5	18.4	20.2	18.3
Ash Handling System	16.3	12.4	13.1	9.8
Electrical Distribution & Switchyard	25.9	26.1	25.9	26.1
Instrumentation & Control	10.6	10.6	12.5	12.5
Site, General	21.9	21.7	21.8	21.7
Buildings & Structures	9.7	9.3	9.7	9.3
Freight, Tax, Contingency, & Other	81.3	82.2	83.8	84.9
Oxidant Supply	11.6	83.8	10.8	84.9
TOTAL, MM$	752.7	800.5	763.7	813.7
TOTAL, $/kW	1,311	1,517	1,284	1,507

Table 5. Capital Costs in Million Dollars, January, 2003

The Indirects category includes expenses such as AFUDC, engineering, project management, construction management, temporary facilities and services during construction, startup, insurance, taxes, and land. Recent escalations in commodity prices such as steel and concrete since January, 2003 are not reflected in the above capital costs.

4.3 Operating and Maintenance Costs

The O&M costs are reported in Table 6, distributed between Fixed and Variable O&M according to the EPRI TAG® basis (see Reference 4). This basis shifts many costs that would normally be considered variable O&M to fixed O&M, and increases the total O&M by approximately $1/MWhr for each case because several items are not capitalized in the TAG approach. In the table below, fixed O&M includes labor, training, building and grounds maintenance, gas turbine long term service agreements, repair costs, spare parts inventory charges, parts for preventive maintenance, outage expenses, operational upgrades, and startup expenses. Variable O&M includes the costs of expendables and natural gas for startup and flare.

	Case 1	Case 2	Case 3	Case 4
Fixed O&M, $/kW-yr	42.30	46.90	43.20	48.80
Variable O&M, $/MWh	0.84	0.94	0.59	0.62

Table 6. Operating and Maintenance Costs

The Variable O&M costs are lower for the syngas cleanup configurations (Cases 3 and 4) because of the ammonia produced in the sour water treatment system. Part of the ammonia produced is used in the SCR, eliminating the need to purchase ammonia, and the rest is sold at 75 percent of the market value. Without this byproduct credit, the Variable O&M for Cases 3 and 4 would be higher than that for Cases 1 and 2 because of the yearly purchase of the CrystaSulf solution.

4.4 Cost of Electricity

The cost of electricity is calculated for each case using the following financial assumptions:

- Plant book life – 20 years
- Carrying charge factor – 0.142
- Capacity factor – 80 percent
- Coal cost – $1.25/MMBtu

The resulting levelized costs for capital, O&M, and fuel, and the cost of electricity for each case are reported in Table 7, in January, 2003 dollars.

	Case 1	Case 2	Case 3	Case 4
Capital, mills/kWh	23.4	27.0	22.9	26.8
O&M, mills/kWh	6.9	7.6	6.7	7.6
Fuel, mills/kWh	10.1	10.3	10.4	10.3
Total COE, mills/kWh	40.4	44.9	40.0	44.8

Table 7. Levelized Capital, O&M, Fuel, and Electricity Costs

The values in Table 7 do not all sum to the given totals due to rounding errors. The calculated values for AFUDC that are included in Table 6 are subtracted out of the total costs so that the standard carrying charge factor can be used in the COE calculations for Table 7.

4.5 Reliability, Availability and Maintainability

A Reliability, Availability and Maintainability (RAM) analysis was conducted on Cases 1 and 2 to calculate the overall yearly availability and to determine which pieces of equipment have the greatest impact on RAM. A liquid oxygen (LOX) system was included in Case 2 as a backup to the ASU, sized to make the oxygen supply in Case 2 as reliable as the air supply in Case 1. Thus the two cases have approximately the same overall Equivalent Availability Factor (EAF), which is calculated to be 89.7 percent with a CT backup fuel, and 83.7 percent with no CT backup fuel. The Effective Forced Outage Rate (EFOR) with backup fuel is approximately 6.5 percent for both cases. These calculations are based on a twelve year maintenance cycle with 7.6 percent unavailability due to planned outages.

This projected availability is higher than the 75 to 80 percent currently achieved by oxygen-blown, entrained-flow IGCC plants (Reference 5). This is primarily because the Transport Gasifier operates at a much lower temperature than an oxygen-blown IGCC plant, extending refractory life and reducing the number and duration of outages, and the Transport Gasifier uses dry feed systems rather than the burner nozzles that require frequent replacement in slurry-fed, oxygen-blown IGCC plants.

The pieces of equipment with the greatest impacts on RAM are listed below, in order of impact on EAF. All other pieces of equipment account for less than 3 percent of the down time.

1. Gas Turbines
2. Steam Turbine
3. Syngas filters
4. HRSGs
5. ASU (for oxygen-blown, if backup LOX were not included)
6. Secondary Syngas Coolers
7. Primary Syngas Coolers
8. Transport Gasifiers

Because of the simple gasifier design of the Transport Gasifier, its impact on unavailability is low.

5.0 Comparisons

Each of the four cases was individually designed and optimized to give the lowest cost of electricity from PRB coal with the lowest reasonable emissions. Comparisons are made below to evaluate the relative merits of the four configurations for this specific purpose.

5.1 Air-blown and Oxygen-blown Gasification with Stack Gas Cleanup

Important differences in the results for air-blown and oxygen-blown gasification with stack gas cleanup are shown in Table 8.

	Case 1	Case 2	Difference
Gasifier Oxidant	air	oxygen	
Emissions Control	stack	stack	
Net Output, MW	574.1	527.8	-8%
ST Output, MW	266.6	227.6	-15%
Auxiliaries, MW	86.6	93.7	+8%
Coal Feed Rate, lb/hr	532,300	497,000	-7%
Cost, $/kW	1,311	1,517	+16%
O&M, mills/kWh	6.9	7.6	+10%
COE, mills/kWh	40.4	44.9	+11%
NOTE: emissions are not equivalent			

Table 8. Air-blown versus Oxygen-blown with Stack Gas Cleanup

The air-blown system (Case 1) produces more power than the oxygen-blown (Case 2) primarily because the larger syngas flow raises more high pressure steam in the syngas cooler. The power consumed by the process air compressor in Case 1 (54.3 MW) is less than that consumed by the ASU in Case 2 (63.6 MW), and the energy is used in the air-blown case to send additional gas through the gasifier and syngas coolers rather than to separate air into nitrogen and oxygen. The coal feed rate is higher in Case 1 because of the energy required to heat the additional larger amount of gas in the gasifier.

The total capital cost of the oxygen-blown gasification plant is about $50 million higher than that of the air-blown plant, giving the air-blown system a significantly lower cost per kilowatt. The cost savings in the oxygen-blown system from smaller gasifiers, syngas coolers, syngas filters, etc. is more than offset by the cost savings in the air-blown system of using an air compressor rather than an ASU. The O&M costs are also higher for the oxygen-blown plant primarily because of the ASU.

The differences in capital and O&M costs lead to a substantially lower levelized cost of electricity for the air-blown configuration.

In these two cases limestone is injected into the gasifier, and the resulting hydrogen sulfide content of the syngas is determined by vapor pressure equilibrium with the calcium sulfide formed in the gasifier and the water in the syngas. Therefore the sulfur concentration is lower in the air-blown Case 1 because it uses less gasifier steam injection than the oxygen-blown Case 2. Since there is no syngas cleanup in between, this also lowers the SO_2 concentration in the CT exhaust (before the FGD system), lowering the acid dewpoint temperature, and thus allowing a lower HRSG exit temperature and more heat to be recovered in the HRSG.

Since the FGD captures the same percent of sulfur in both cases, the sulfur emissions are lower in Case 1. However, the sulfur capture in the FGD could easily be increased at the cost of a higher gas pressure drop, so the lower SO_2 emissions for the air-blown case are not a significant advantage. The NO_X, mercury, and particulate emissions are similar for both cases.

Because of the cost of electricity and net power output differences discussed above, for a PRB-fueled Transport Gasification combined cycle with stack gas cleanup that produces only power, air-blown gasification is preferred.

5.2 Air-blown and Oxygen-blown Gasification with Syngas Cleanup

The results for air-blown and oxygen-blown gasification with syngas cleanup that differ significantly are shown in Table 9.

	Case 3	Case 4	Difference
Gasifier Oxidant	air	oxygen	
Emissions Control	syngas	syngas	
Net Output, MW	594.8	540.0	-9%
ST Output, MW	288.3	241.0	-16%
Auxiliaries, MW	87.5	95.0	+9%
Coal Feed Rate, lb/hr	566,400	511,500	-10%
Cost, $/kW	1,284	1,507	+17%
O&M, mills/kWh	6.7	7.6	+13%
COE, mills/kWh	40.0	44.8	+12%
NOTE: emissions are not equivalent			

Table 9. Air-blown versus Oxygen-blown with Syngas Cleanup

The difference in net power output is again mainly due to the difference in the steam turbine output. As before, the larger air-blown syngas flow (in Case 3) generates more steam in the syngas coolers than does the oxygen-blown syngas flow (in Case 4). And, the ASU auxiliary load (66.3 MW versus 57.3 MW for the air compressor) leads to a higher auxiliary load for the oxygen-blown case, further widening the difference in power output. The coal feed rate is higher in the air-blown case because of the coal required to heat the nitrogen in the gasifier.

The total cost difference between the air-blown and oxygen-blown configurations with syngas cleanup is very close to that seen with stack gas cleanup. This shows that for these designs, the cost of syngas cleanup is not prohibitively high for air-blown gasification. The total cost of the CrystaSulf system is $20 million in the air-blown case and $15 million in the oxygen-blown case. The O&M costs are again higher for the oxygen-blown configuration due to the maintenance requirements of the ASU.

The lower O&M costs and capital costs combine to give the air-blown Case 3 a levelized cost of electricity about a half a cent lower per kWh than that of the oxygen-blown Case 4.

While the NO_X, particulates, and mercury emissions are similar for both cases, the sulfur emissions are lower for the oxygen-blown system. This is because both the COS hydrolysis and CrystaSulf systems have the same sulfur slip (in terms of ppmv) whether the syngas is air-blown or oxygen-blown. The lower oxygen-blown syngas flow rate therefore results in proportionally lower sulfur emissions, although both are quite low in absolute terms.

Because the sulfur emissions are very low for both cases, the power output and cost advantages of air-blown gasification make it preferable for a PRB-fueled Transport Gasification combined cycle with syngas cleanup that produces only power.

5.3 Stack Gas and Syngas Cleanup for Air-Blown Gasification

Since the air-blown cases have been preferred in the comparisons thus far, they are compared with stack gas and syngas cleanup in Table 10. Only significant differences in the results are shown below.

	Case 1	Case 3	Difference
Gasifier Oxidant	air	air	
Emissions Control	stack gas	syngas	
Net Output, MW	574.1	594.8	-4%
ST Output, MW	266.6	288.3	+8%
Net Efficiency (HHV), %	42.1	41.0	
NOTE: emissions are not equivalent			

Table 10. Stack Gas and Syngas Cleanup for Air-Blown Gasification

The system with syngas cleanup (Case 3) delivers more power than the system with stack cleanup (Case 1) because of the absence of FGD system fans, and because the cooler syngas temperature to the CT necessitates a higher syngas flow and thus more steam generated in syngas cooling. The stack gas cleanup configuration (Case 1) has a higher efficiency because it does not incur the losses associated with cooling the syngas to near atmospheric temperature for cleanup and also because of the higher syngas delivery temperature to the CT. The power increase is of much more value than the efficiency loss in a typical utility setting, so Case 3 is preferred on performance.

Another advantage for Case 3 is much lower emissions of NO_X and mercury. In Case 3, most of the ammonia is removed from the syngas when it is cooled for sulfur removal, greatly reducing NO_X production from fuel-bound nitrogen. And mercury capture from syngas by a carbon bed is more efficient than the mercury capture in the FGD system.

Since the syngas-cleanup alternative also has a slightly lower cost per kW, syngas cleanup is preferred for an air-blown PRB-fueled Transport Gasification combined cycle that produces only power.

6.0 Areas of Interest for Future Study

Two similar studies are currently in progress at the time of publication: Cases 5 and 6 both investigate carbon capture from a PRB-fueled Transport Gasification combined cycle using a conventional amine system. Case 5 uses air-blown gasification and Case 6 uses oxygen-blown. Results will be presented in a follow-up paper in the near future.

Other areas of interest for future study include the following:

- Using advanced gas cleanup options such as direct oxidation of sulfur, high-temperature ammonia cracking, or catalytic filter elements
- Changing the gasifier fuel from PRB to lignite
- Evaluating CO_2 capture as a retrofit to an existing Transport Gasification system
- Evaluating a Selexol system rather than an amine system to capture CO_2
- Repowering an existing 2x1 natural gas-fired combined cycle
- Using the newly-developed-for-syngas GE 7FB gas turbine in place of the 7FA+e

7.0 Conclusion

These studies have shown that for the production of power from low-sulfur PRB coal with currently available technologies, air-blown Transport gasification is preferable to oxygen-blown Transport gasification. They have also shown that for these project configurations and design assumptions, syngas cleanup is preferable to stack gas cleanup.

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DISCLAIMER

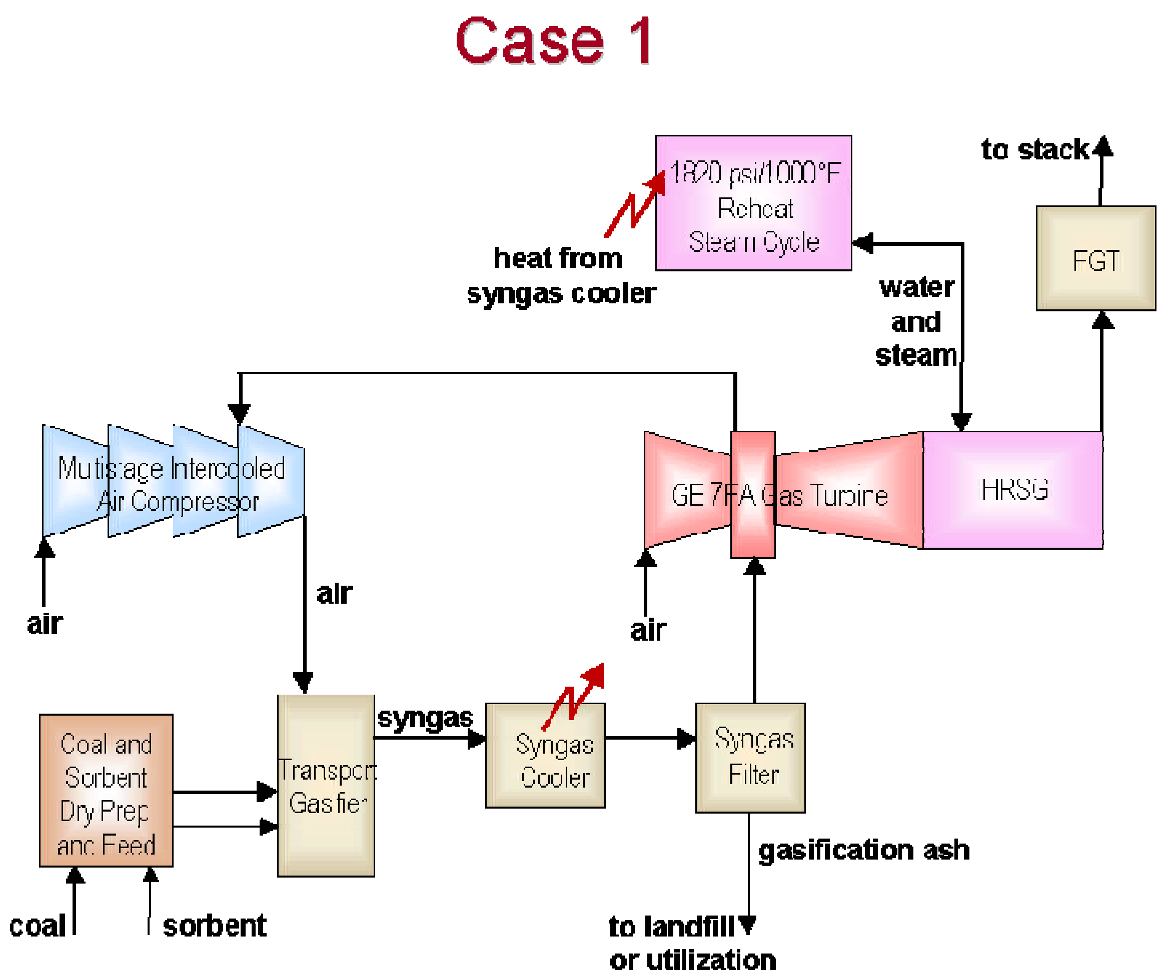

Figure 1. Case 1 Simplified Process Flow Diagram

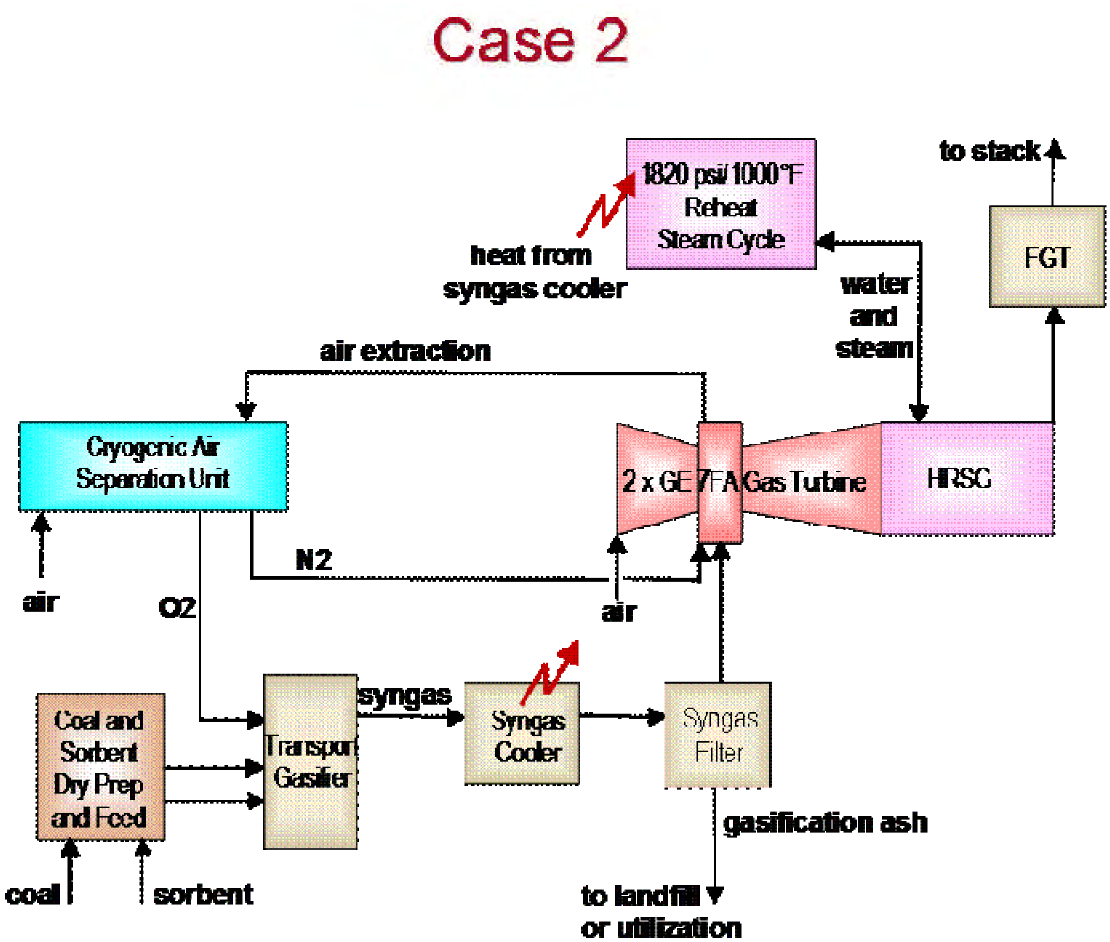

Figure 2. Case 2 Simplified Process Flow Diagram

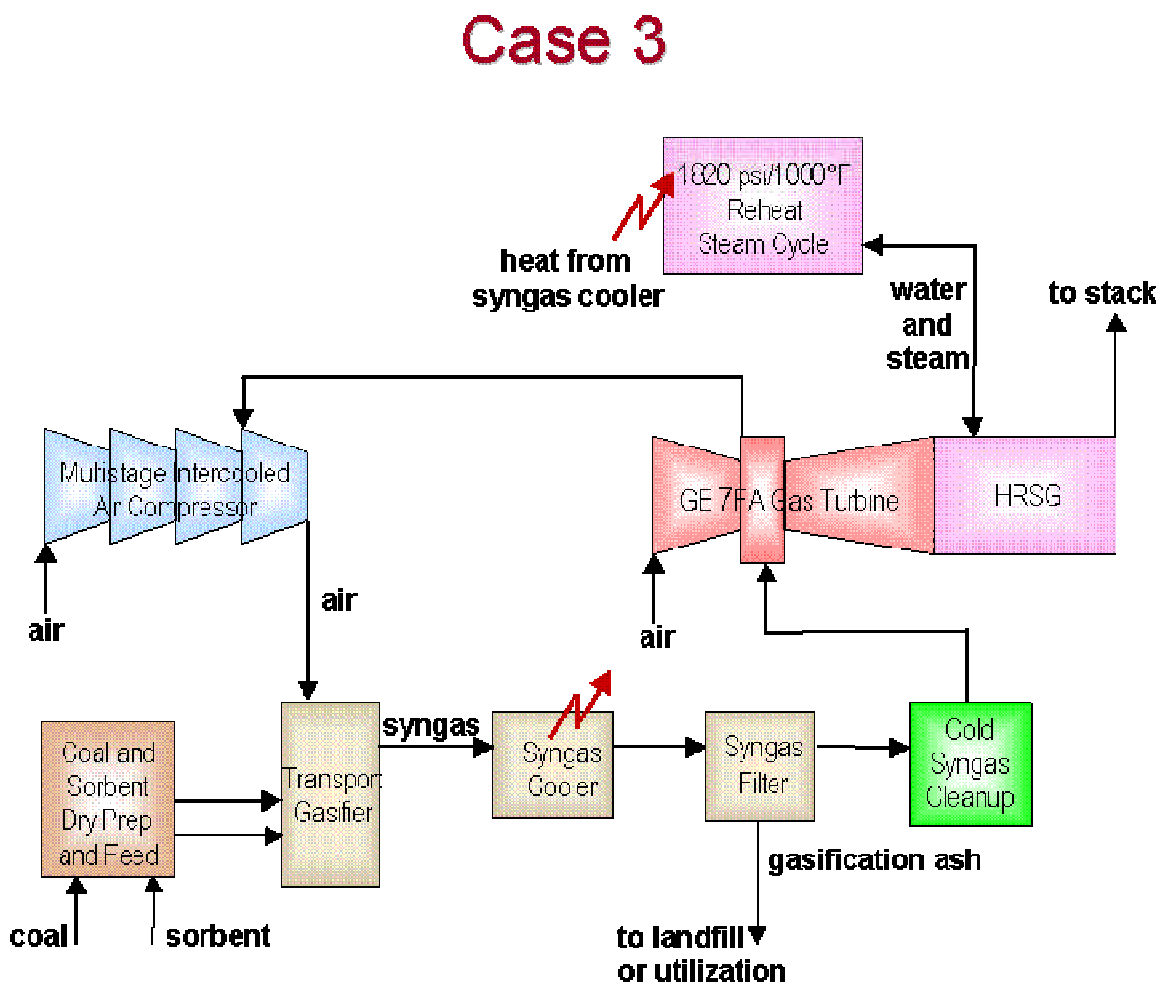

Figure 3. Case 3 Simplified Process Flow Diagram

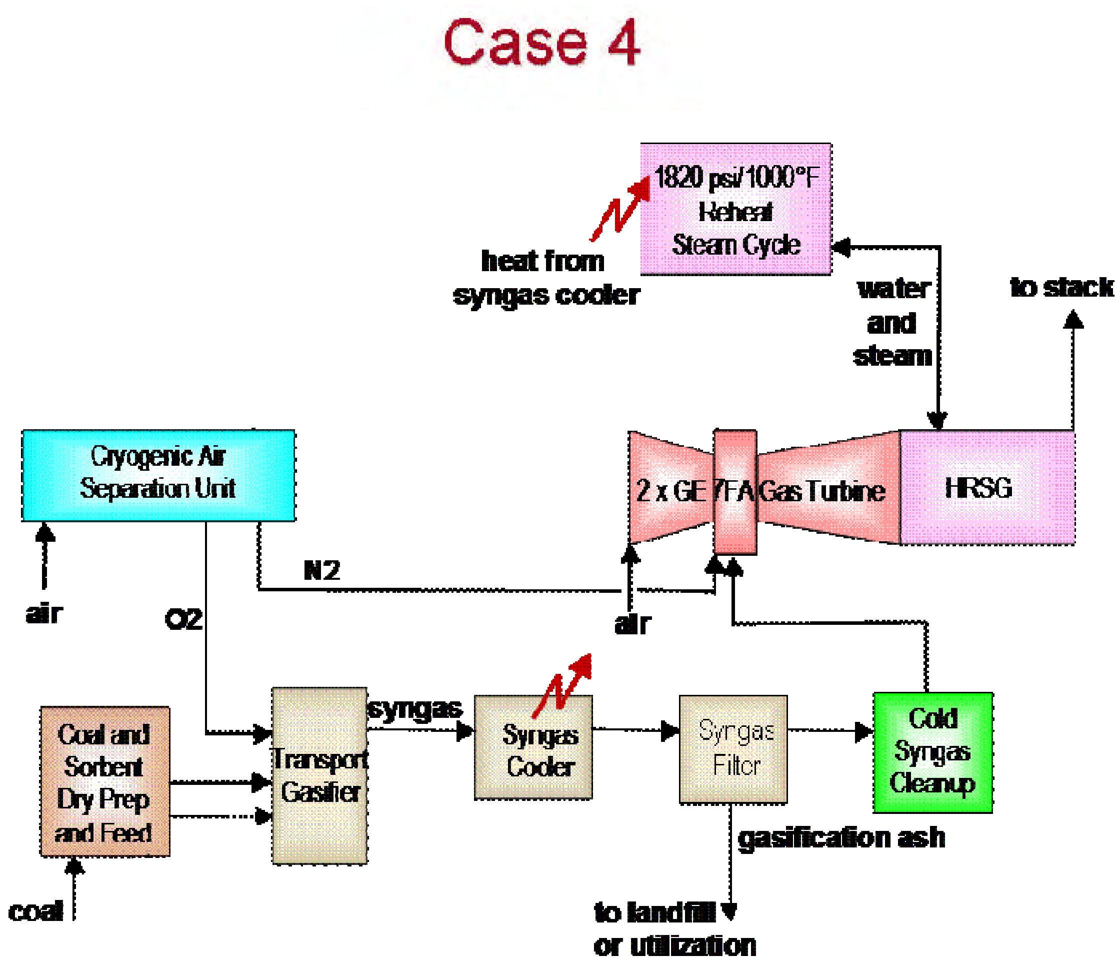

Figure 4. Case 4 Simplified Process Flow Diagram

CrystaSulf Layout

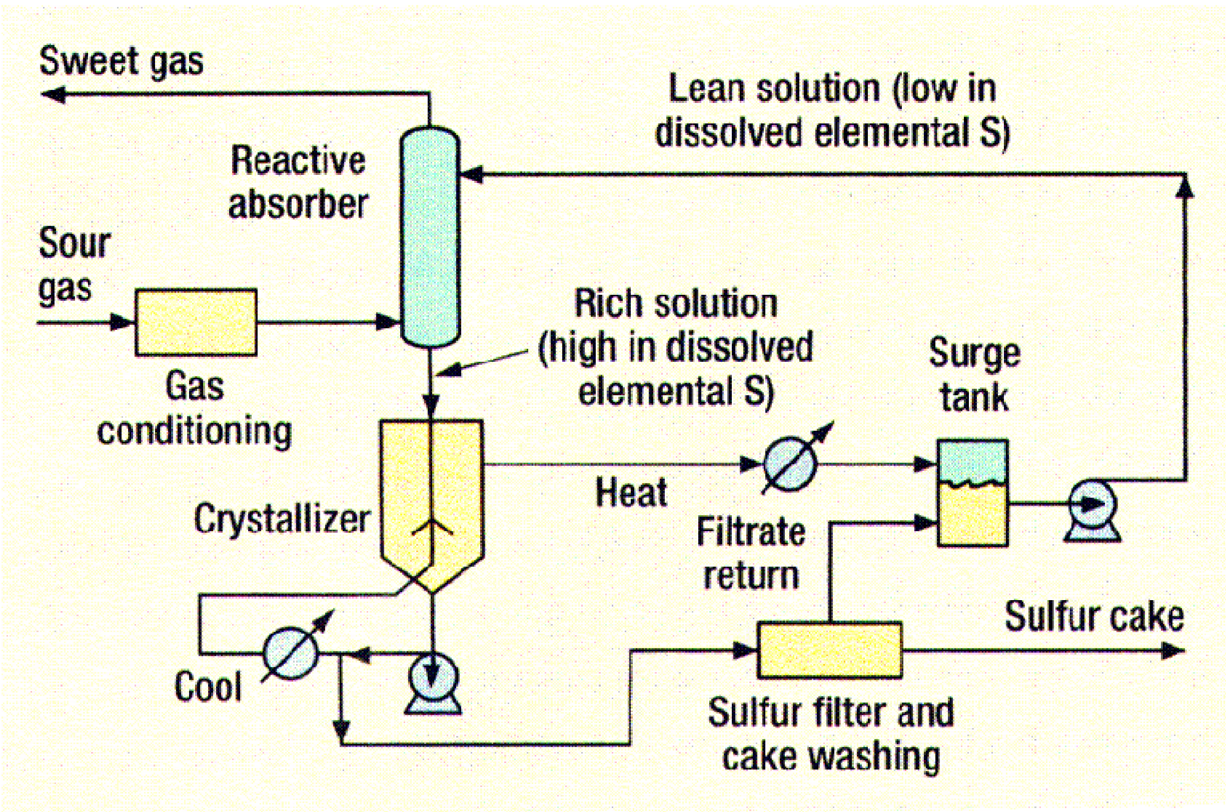

Figure 5. CrystaSulf Process Layout (From Gas Processes Handbook – 2004, Gas Technology Products, LLC)