Prepared for:
RTI International

Preliminary Feasibility Analysis of RTI Warm Gas Cleanup (WGCU) Technology

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RTI International (RTI), under a DOE Cooperative Agreement DE-FC26-05NT42459, contracted Nexant, Inc. (Nexant) to perform a high-level techno-economic assessment of their warm gas cleanup (WGCU) technology for integrated gasification combined cycle (IGCC) applications. Nexant was to develop conceptual IGCC plant designs with which the feasibility of WGCU for high temperature H_2S removal can be evaluated in comparison with a conventional acid gas removal (AGR) technology. A state-of-the-art 600 MWe IGCC conceptual plant design based on Selexol AGR was chosen as the reference plant, using two different Illinois No. 6 coal feeds from the DOE NETL's Quality Guidelines for Energy System Studies document. The IGCC facility is to be a greenfield plant located in the Midwest United States, next to the Mississippi River, where large equipment can be easily barged to site. Figure 1.1 shows an overall block flow diagram (BFD) of the reference IGCC plant (Reference IGCC) showing the inter-connectivity of the various major processing plants. The corresponding BFD of the WGCU based IGCC plant (WGCU IGCC) is shown in Figures 1.2.

The overall performance comparisons of the Reference IGCC design versus the WGCU IGCC design are presented in Table 1.1, for the two DOE Illinois No. 6 design coals. Detailed power balance comparisons are shown in Table 1.2.

As shown, there are significant differences in property between the 2006 Illinois No. 6 design coal feed and that of the 2004 design coal. The 2006 design coal feed has over 6% increase in heating value, about 32% less in ash, and 44% less in sulfur. Collectively, it resulted in a higher overall IGCC plant efficiency. The 2006 design coal, however, has much higher chloride content (almost a factor of 6); thus it needs to be designed with a much larger sour water stripper unit, resulting in an increase in the overall plant water consumption. The steam turbine output is also significantly reduced due to an increase in sour water stripper reboiling steam consumption. A similar trend occurs with the WGCU IGCC design, except one notably difference; because the WGCU process uses dry chloride removal, its steam turbine output is less affected by the higher coal chloride content.

For a given coal feed, performance differences between the Reference IGCC design with a conventional low temperature AGR process and that of WGCU IGCC design are quite significant: 2.0% and 3.6% (HHV) increase in overall thermal efficiency for the 2004 and 2006 Illinois No. 6 coal feed respectively. This increase in overall thermal efficiency is not only attributable to the ability of WGCU technology for removing sulfur from the hot raw syngas at high temperature, but also its companion technologies of DSRP of high temperature sulfur recovery, and the design of a convective cooler upstream of the WGCU for maximum waste heat recovery.

Table 1.3 compares the estimated December 2006 capital investment required to build the 600 MWe IGCC plants at a midwest US site. These estimated costs are capacity factored based on Nexant's in-house data with an accuracy no better than +/- 30%. Start-up and training costs, licensing/ royalty fees, contingencies and owner's costs are not included in Table 1.3. In general, the WGCU IGCC plants are about 5% cheaper to build than the Reference IGCC plants.

On a total plant cost per installed capacity, the WGCU plants cost about 14% less due to the higher thermal efficiency.

Table 1.4 shows the estimated itemized annual operating cost breakdowns for the 600 MWe IGCC plant. The operating cost is based on an annual overall on-stream factor of 85%. Coal cost is based on $2.00/MMBtu (HHV as-received basis). In general, the cost-of-electricity for the WGCU IGCC plants is about 5 to10% cheaper than the Reference IGCC plants.

Based on overall efficiency, capital cost and cost-of-electricity, the WGCU IGCC design appears to be an attractive alternative to the Selexol-based Reference IGCC design, assuming both design have the same on-stream factor (85%). While the Reference IGCC plant's AGR, SRU and TGTU are all relatively mature technologies, RTI's WGCU/DSRP is a new technology not yet commercially demonstrated, and may be expected to have lower on-stream factor. With the estimated cost-of-electricity advantage at constant on-stream factor, the WGCU design should remain competitive with up to 5-to-8 percentage point lower in on-stream factor (77% to 80%).

In conclusion, RTI WGCU appears to be an attractive alternative to the Selexol-based IGCC design.

Figure 1.1
Reference IGCC Overall Process Block Flow Diagram

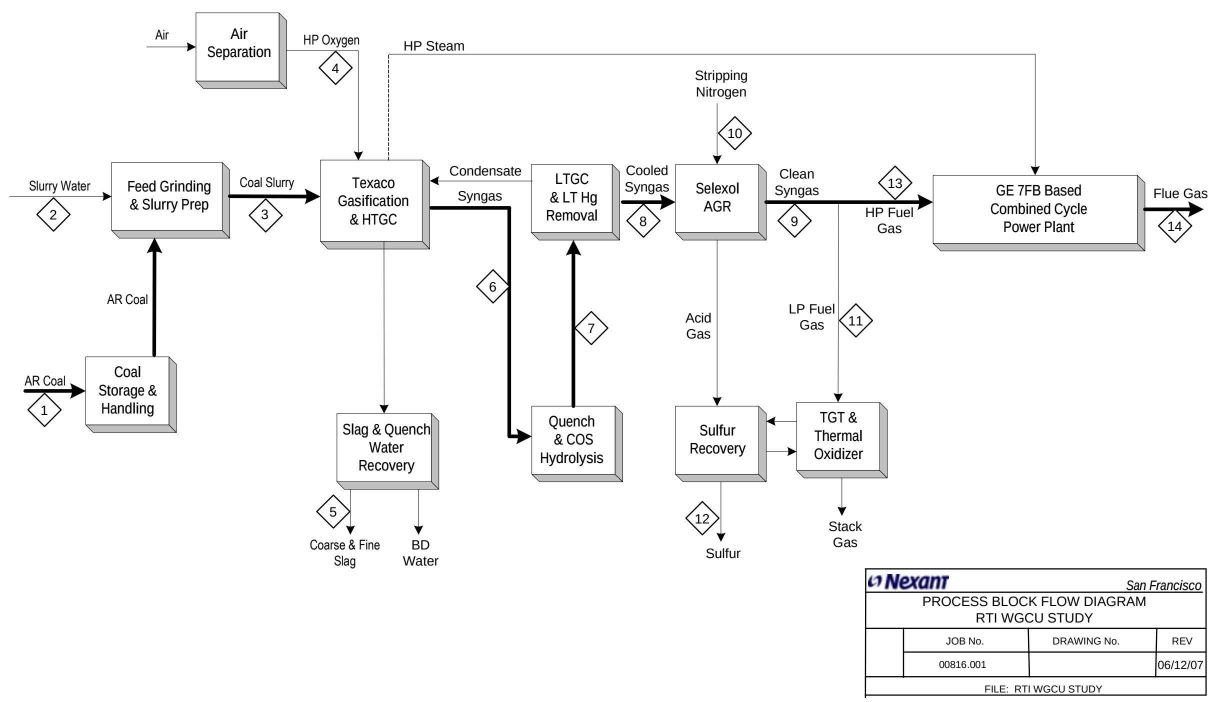


Figure 1.2
WGCU IGCC Overall Process Block Flow Diagram

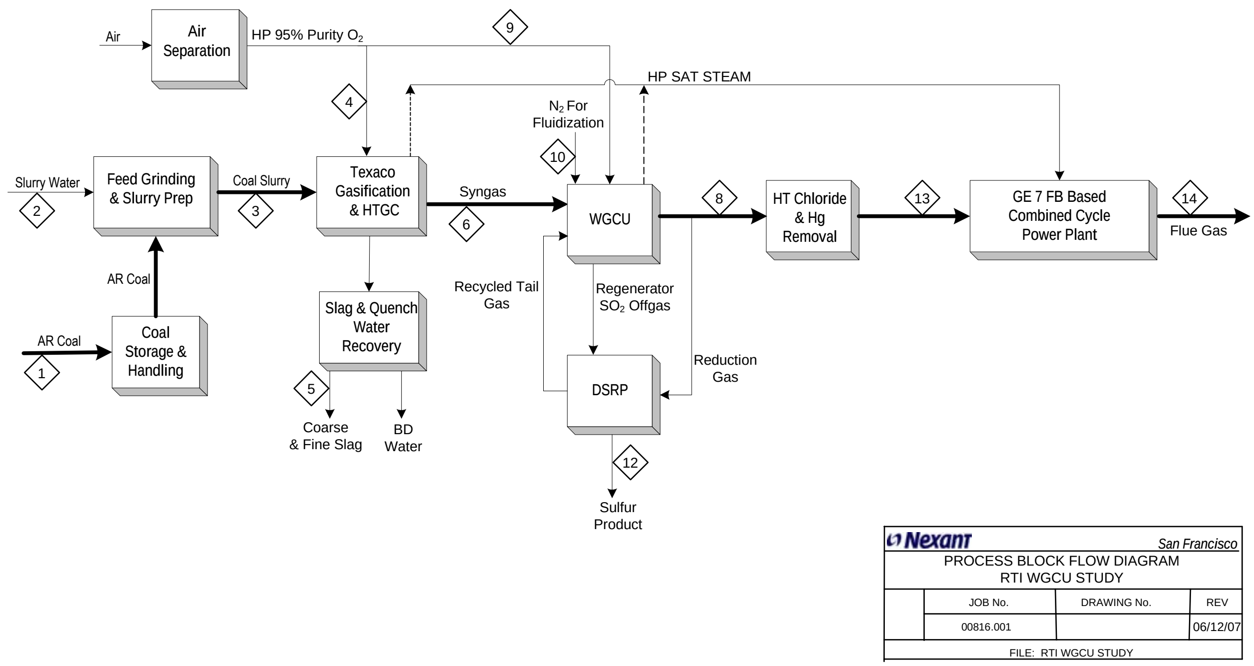


Table 1.1
Overall Performance Comparison Summary

	CASE 1 Reference IGCC 2004 NETL Coal	CASE 2 WGCU IGCC 2004 NETL Coal	CASE 3 Reference IGCC 2006 NETL Coal	CASE 4 WGCU IGCC 2006 NETL Coal
AR COAL PROPERTIES:				
Ultimate Analysis, Wt%				
Carbon	60.42		63.75	
Hydrogen	3.89		4.50	
Nitrogen	1.07		1.25	
Sulfur	4.45		2.51	
Oxygen	7.91		6.88	
Chloride	0.05		0.29	
Ash	14.25		9.7	
Moisture	7.97		11.12	
Total Wt%	100.00		100.00	
HHV, Btu/lb	10,999		11,666	
GASIFIER TYPE	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F
SLURRY FEED, Wt% MF Coal	63.4	63.4	63.4	63.4
SLURRY LB H2O / LB MAF COAL	0.683	0.683	0.648	0.648
SYNGAS COOLING – High Temp	Radiant to 1300 ^oF	Radiant to 1300 ^oF	Radiant to 1300 ^oF	Radiant to 1300 ^oF
SYNGAS COOLING – Low Temp	Quench/AC/CW To 90 ^oF	Convective to 550 ^oF	Quench/AC/CW To 90 ^oF	Convective to 550 ^oF
MERCURY REMOVAL	90% , LT	90% , HT	90% , LT	90% , HT
CHLORIDE REMOVAL	Wet Scrub	Dry Adsorb	Wet Scrub	Dry Adsorb
ACID GAS REMOVAL	Selexol	WGCU	Selexol	WGCU
CO2 RECOVERY / PRE-INVESTMENT	No	No	No	No
SULFUR RECOVERY	Claus + TGTU	DSRP	Claus + TGTU	DSRP
GAS TURBINE	2 x GE 7FB	2 x GE 7FB	2 x GE 7FB	2 x GE 7FB
GT FUEL LHV, Btu/SCF Incl Diluent	163	164	161	162
GT FUEL GAS LHV, MMBtu/Hr	3,488	3,392	3,680	3,630
FUEL GAS TEMP @ GTCC B/L	340 ^oF	550 ^oF	340 ^oF	550 ^oF
GT EXHAUST GAS TEMPERATURE	1076 ^oF	1055 ^oF	1119 ^oF	1109 ^oF
STEAM TURBINE / HRSG	2 x Re-Heat 1000 ^oF / 1000 ^oF	2 x Re-Heat 1000 ^oF / 950 ^oF	2 x Re-Heat 1000 ^oF / 1000 ^oF	2 x Re-Heat 1000 ^oF / 1000 ^oF
CONSUMABLES:				
AR Coal Feed,STPD	5,763	5,763	5,467	5,467
Raw Water, GPM	4,227	4,422	5,646	4,288
95.0% O2, STPD	4,576	5,006	4,665	4,895
99% N2, STPD	6,765	2,919	7,024	3,959
NG Import, MMLHV/Hr	0	0	0	0
PRODUCTS:				
Power Export, MWe	558	589	585	641
Sulfur, STPD	255	256	137	137
Slag & Ash, STPD Dry	870	870	562	562
Waste Water, GPM	1,306	1,084	2,798	1,085
Recovered CO2, STPD	0	0	0	0
OVERALL ELEC EFFICIENCIES:				
Gross Heating Value Basis	36.1 % HHV	38.1 % HHV	37.6 % HHV	41.2 % HHV
Net Heating Value Basis	37.6 % LHV	39.7 % LHV	39.3 % LHV	43.1 % LHV

Table 1.2
IGCC Plant Overall Power Balance Comparison

	CASE 1 Reference IGCC 2004 NETL Coal	CASE 2 WGCU IGCC 2004 NETL Coal	CASE 3 Reference IGCC 2006 NETL Coal	CASE 4 WGCU IGCC 2006 NETL Coal
POWER BALANCE				
GENERATION, MWe:				
Gas Turb Generator System	430.7	416.8	455.7	449.3
Steam Turb Generator System	260.8	300.3	263.2	316.7
Total Gross Output	691.5	717.1	719.0	766.0
CONSUMPTION, MWe:				
Coal Handling/Storage	5.6	5.6	5.1	5.1
Gasification/Feed Prep	4.4	4.4	2.8	2.8
Air Separation	38.4	42.1	39.2	41.1
O2 Compression	22.6	24.8	23.1	24.2
Shift & LT Gas Cooling	0.9	(0.0)	0.7	0.0
Acid Gas Removal & SWS	3.0	0.0	2.0	0.0
Sulfur Recovery	1.0		0.5	
RTI Warm Gas Clean Up/DSRP	---	11.5	---	6.1
CO2 Dehydr'n & Comp	0.0	0.0	0.0	0.0
Plt Air/Instru Air/N2 System	30.4	11.8	31.7	17.3
HRSG/Boiler Plt/BFW/DM/Cond	7.3	8.0	8.2	7.9
CW Pumps & CT Fans	8.2	8.1	8.2	8.1
Flue Gas CO2 Recovery	---	---	---	---
BOP	11.5	11.7	12.5	12.4
Total Consumption	133.2	127.9	134.0	125.1
NET POWER EXPORT, MWe	558.3	589.2	585.0	640.9

Table 1.3
2006 IGCC Plant Capital Cost

	CASE 1 Reference IGCC 2004 NETL Coal	CASE 2 WGCU IGCC 2004 NETL Coal		CASE 3 Reference IGCC 2006 NETL Coal	CASE 4 WGCU IGCC 2006 NETL Coal
CAPITAL COSTS, 2006 $MM					
Coal Handling/Storage	18.4	18.4		17.8	17.8
Gasification/Feed Prep	159.0	159.0		151.5	151.5
Spare Gasifiers	79.5	79.5		75.8	75.8
Air Separation	79.4	84.6		80.5	83.2
O2 Compression	Incl ASU	Incl ASU		Incl ASU	Incl ASU
COS Hydrolysis & LTGC	36.8	0.0		37.2	0.0
Acid Gas Removal & SWS	131.8	5.8		147.9	4.3
Sulfur Recovery	25.4	0.0		16.4	0.0
Tail Gas Treating Unit	32.3	0.0		20.8	0.0
RTI Warm Gas Clean Up/DSRP	0.0	196.8		0.0	164.1
CO2 Dehydr'n & Comp	---	---		---	---
Plt Air/Instru Air/N2 System	23.1	11.6		23.8	15.0
Gas Turb Generator System	140.7	137.5		146.4	145.0
HRSG/Boiler Plt/BFW/DM/Cond	48.2	54.5		49.0	55.6
Steam Turb Generator System	48.9	54.1		49.2	56.1
CW Pumps & CT Fans	17.2	18.2		16.5	18.6
Flue Gas CO2 Recovery	---	---		---	---
BOP	164.6	165.7		179.9	168.7
Total Installed Cost	1,005.2	985.7		1,012.6	955.4
Home Office Cost	100.5	98.6		101.3	95.5
Contingency	Excluded	Excluded		Excluded	Excluded
Total Plant Cost	1,105.8	1,084.3		1,113.8	1,050.9
Net Power Export, MWe	558.3	589.2		585.0	640.9
Total Plant Cost per Unit Output, $/KWe	1,981	1,841		1,904	1,640

Table 1.4
IGCC Plant Annual Operating Costs Comparison

	CASE 1 Reference IGCC 2004 NETL Coal	CASE 2 WGCU IGCC 2004 NETL Coal	CASE 3 Reference IGCC 2006 NETL Coal	CASE 4 WGCU IGCC 2006 NETL Coal
INCOMES & EXPENSES, $MM/Yr:				
AR Coal Cost	78.7	78.7	79.2	79.2
Raw Water Import	0.7	0.7	0.9	0.7
Cat & Chem Consumptn	6.0	10.0	6.0	15.0
Royalties	0.0	0.0	0.0	0.0
Mainten Labor & Mat	33.2	32.4	33.4	31.4
Admin & Labor Salary	14.4	14.4	14.4	14.4
Overheads & Benefits	5.0	5.0	5.0	5.0
Insurances	11.1	10.8	11.0	10.5
Local Taxes	11.1	10.8	11.0	10.5
Sulfur Sale	(5.5)	(5.6)	(3.0)	(3.0)
Ash & Slag Disposal	2.7	2.7	1.7	1.7
Waste Water Disposal	0.0	0.0	0.0	0.0
CO2 Sequestn Credit	0.0	0.0	0.0	0.0
CO2 Emission Penalty	0.0	0.0	0.0	0.0
Bank Loan Repayment	97.3	95.4	98.0	92.6
Investment Recovery	53.6	52.5	53.9	51.0
Total Annual Expenditure	308.1	307.8	311.9	309.0
Annual Power Export, MW-Hr	4,154,868	4,387,180	4,355,910	4,772,880
Cost of Electricity, ¢/kW-Hr	7.42	7.02	7.16	6.47

2.1 BACKGROUND

RTI International (RTI), under a DOE Cooperative Agreement DE-FC26-05NT42459, contracted Nexant, Inc. (Nexant) to perform a high-level techno-economic assessment of their warm gas cleanup (WGCU) technology for integrated gasification combined cycle (IGCC) applications. Nexant was to develop conceptual IGCC plant designs with which the feasibility of WGCU for high temperature H_2S removal can be evaluated in comparison with a conventional acid gas removal (AGR) technology. A state-of-the-art IGCC conceptual plant design was chosen as reference plants, using two different Illinois No. 6 coal feeds from the DOE NETL's Quality Guidelines for Energy System Studies document.

2.2 SCOPE OF WORK

Nexant's scope of work is to develop companion GE gasification-based conceptual IGCC designs; perform heat & material balances, and estimate their capital and O&M costs; allowing the techno-economic feasibility of RTI's Warm Gas Clean Up (WGCU) technology to be evaluated. The IGCC designs are to be based on a generic U.S. Midwest site, and having a nominal 600 MW capacity. RTI's WGCU technology is to be evaluated and compared with the use of a conventional physical solvent-based AGR (acid gas removal) technology of Selexol, coupled with a Claus plant for sulfur recovery and a SCOT plant for tail gas treating.

The Case 1 Reference IGCC design is to have the following key technology components, as desired by RTI/DOE:

- GE gasifiers operating under a radiant cooling only mode for waste heat recovery,
- Conventional cryogenic air separation units (ASU), producing 95% purity oxygen (O_2) with no integration to the power train,
- Selexol for AGR,
- Conventional Claus sulfur recovery with SCOT tail gas treating,
- Low-temperature mercury (Hg) removal, and
- A combined cycle power plant, based on GE 7FB turbine.

The IGCC designs are for power production only. Also, CO_2 capture will not be considered to be consistent with the RTI WGCU design where pre-investing for future CO_2 capture will not be included at this point.

Case 2 is to be a companion design of Case 1, using RTI's WGCU and DSRP technologies for syngas desulfurization and sulfur recovery respectively. RTI's WGCU technology is based on a fluidized bed absorber (reactor)/re-generator system of which RTI provided Nexant with sufficient data from its pilot plant runs to size and cost the absorber/re-generator system. Nexant is to size and cost all other conventional unit operation processing units associated with the system.

As part of the Case 2 study, Nexant is to identify (as appropriate) and recommend any additional processes and/or complementary technologies that maybe required for viable WGCU IGCC design integration.

Using a separate Illinois No. 6 coal feed, two additional designs were developed, a Case 3 IGCC and a Case 4 WGCU/DSRP IGCC design. Other than the differences in the coal property, the overall process configurations for these two designs are the same with that of Case 1 and 2 respectively.

2.3 EXECUTION METHODOLOGY

Nexant carried out the current study using an in-house IGCC Plant Simulation Model, which is a large spreadsheet capable of performing overall process heat and material balances. In addition, the model does a complete balance of plant, calculating and balancing all in-plant power, steam and condensate utility usages. It is a useful tool for a systematic and consistent evaluation of different IGCC configurations, with the ability to quickly compare various design integration causes and effects. The process simulation model is linked to a companion cost and economic modulus that can estimate the capital and annual operating and maintenance costs of the individual plant components and perform simple economic evaluation of the overall process.

As agreed upon with RTI/DOE, Nexant prepared a design basis document and recommendation of various process flow schemes for both RTI and DOE to review and approve, before detailed design H&M balance work were carried out. Design bases for the current study are presented in the next section.

In developing the design and cost of the various major IGCC process components (e.g., ASU, gasifier and radiant cooler, and the power train, etc.,) Nexant drew heavily from our in-house database of process plant performance and costs. In some situations, technology vendors were contacted for updated performance and cost information – e.g., UOP for Selexol.

The IGCC plants are designed for a generic U.S. Midwest site, producing approximately 600 MW of power. This section documents the approved design basis and the various technology components selected for the study.

- Coal Feed
  - High sulfur, high ash, low chloride Illinois No. 6 design coal #1 (2004 NETL) with typical analysis shown in Table 3.1.
  - Low sulfur, low ash, high chloride Illinois No. 6 design coal #2 (2006 NETL) with typical analysis shown in Table 3.2.
- Site Conditions – Typical Southern Illinois
  - Atmospheric Pressure 14.7 psia
  - Ambient Temp (Dry Bulb) 60 ^{o}F(annual avg)
  - Relative Humidity, % 60% (annual avg)
  - Ambient Wet Bulb Temp 51.5 ^{o}F (annual avg)
  - Ambient Air Composition, Vol%:

Nitrogen	78.08
Argon	0.94
Oxygen	20.95
Carbon Dioxide	0.03
Total Vol% (dry)	100.00

- IGCC Production and Plant Capacity
  - Base-loaded (85%+ on stream factor) power production.
  - Nominal 600 MW capacity.
- Gasification Technology: GE oxygen-blown entrained-flow gasifier under radiant-cooling-only mode of operation to generate 1300 ^{o}F syngas.
- Air Separation (ASU)
  - Conventional cryogenic separation technology.
  - No GT air extraction integration.
  - 95% oxygen purity.
- High Temperature Heat Recovery: Fire-tube boiler design for sensible heat recovery from raw syngas as part of the gasifier radiant cooler design.
- Carbon Dioxide Removal: No CO_2 recovery, and no pre-investment for future CO_2 recovery.

- Combined Cycle Power Plant
  - GE 7FB turbine based GTCC.
  - No GT air extraction integration with ASU.
- Offsite/Utility Facilities
  - Steam pressure and temperatures, see Table 3.4.
  - Water supply & return conditions see Table 3.5.
  - Natural gas compositions and properties see Table 3.6.
  - N_2, instrument air & electrical, see Table 3.7.
- Reference IGCC Design of Cases 1 & 3 - Low Temperature Syngas Cooling Followed-by Conventional AGR for Sulfur Removal
  - Water quenched and scrubbed 1300 ^oF syngas to remove trace contaminants.
  - COS hydrolysis to convert 99% of the COS into H_2S.
  - 90% mercury removal with activated carbon before AGR.
  - Commercial low temperature Selexol AGR process.
  - 10 ppmv total sulfur in syngas from AGR.
  - 25% by volume (dry basis) H_2S in acid gas from AGR.
  - Sulfur Recovery & Tail Gas Treating: Commercial Claus followed by SCOT process.
  - No CO_2 recovery.
- WGCU IGCC Design of Cases 2 & 4 - RTI Process Performance and Design Conditions Provided by RTI
  - Regenerative ZnO-based sorbent process in transport reactor configuration.
  - WGCU absorption operation
    - Total sulfur content in clean syngas - 10 ppmv
    - HCl content in clean syngas - 50 ppbw
  - DSRP & sulfur reduction reactors operation
    - Thermally integrated with WGCU's desulfurization process
    - Liquid elemental sulfur byproduct
    - Tailgas recycled into WGCU's desulfurization process

Table 3.1
Illinois No. 6 Design Feed #1 – (2004 NETL) Coal Analysis *

	As Received	Dry
Proximate Analysis, Wt%		
Moisture	7.97	---
Volatiles	36.86	40.05
Sulfur	4.45	4.83
Fixed Carbon	36.47	39.64
Ash	14.25	15.48
Total Wt%	100.00	100.00
Ultimate Analysis, Wt%:		
Carbon	60.42	65.65
Hydrogen	3.89	4.23
Nitrogen	1.07	1.16
Sulfur	4.45	4.83
Oxygen	7.91	8.60
Chloride	0.05	0.05
Ash	14.25	15.48
Moisture	7.97	---
Total Wt%	100.00	100.00
HHV, Btu/lb	10,999	11,951
LHV, Btu/lb	10,545	11,549

Ash Analysis, Wt%:	
Silica, SiO_2	51.4
Alumina, Al_2O_3	19.7
Ferric Oxide, Fe_2O_3	16.3
Titania, TiO_2	1.0
Lime, CaO	4.2
Magnesia, MgO	1.0
Potassium Oxide, K_2O	2.2
Sodium Oxide, Na_2O	1.3
Sulfur Trioxide, SO_3	2.6
Phosphorus Pentoxide, P_2O_5	0.2
Undetermined	0.1
Total Wt%	100.0
Ash Fusion Temperature (Reducing), ^{o}F:	
Initial Deformation	1960
Spherical	2095
Hemispherical	2170
Fluid	2280

* Proximate Analysis, Ultimate Analysis, HHV and LHV are from February 2004 NETL “Quality Guidelines for Energy System Studies”. Ash Analysis and Fusion temperatures are per Nexant in-house data.

Table 3.2
Illinois No. 6 Design Feed #2 – (2006 NETL) Coal Analysis *

	As Received	Dry
Proximate Analysis, Wt%		
Moisture	11.12	---
Volatiles	34.99	39.37
Sulfur	----	---
Fixed Carbon	44.19	49.72
Ash	9.70	10.91
Total Wt%	100.00	100.00
Ultimate Analysis, Wt%:		
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Sulfur	2.51	2.82
Oxygen	6.88	7.75
Chloride	0.29	0.33
Ash	9.70	10.91
Moisture	11.12	---
Total Wt%	100.00	100.00
HHV, Btu/lb	11,666	13,126
LHV, Btu/lb	11,252	12,712

Ash Analysis, Wt%:	
Silica, SiO_2	51.4
Alumina, Al_2O_3	19.7
Ferric Oxide, Fe_2O_3	16.3
Titania, TiO_2	1.0
Lime, CaO	4.2
Magnesia, MgO	1.0
Potassium Oxide, K_2O	2.2
Sodium Oxide, Na_2O	1.3
Sulfur Trioxide, SO_3	2.6
Phosphorus Pentoxide, P_2O_5	0.2
Undetermined	0.1
Total Wt%	100.0
Ash Fusion Temperature (Reducing), ^oF:	
Initial Deformation	1960
Spherical	2095
Hemispherical	2170
Fluid	2280

* Revised (unpublished at start of this study) NETL "Quality Guidelines for Energy System Studies"; Design Illinois No. 6 Coal Feed used in the DOE report '2006 Cost and Performance Comparison of Fossil Energy Power Plants." Ash Analysis and Fusion temperatures are per Nexant in-house data

Table 3.3
WGCU Design Feed Gas (Based on 2004 NETL Coal) Specifications

Feed Gas Compositions, Vol%:	
Hydrogen, H_2	29.229
Carbon Monoxide, CO	35.884
Carbon Dioxide, CO_2	13.642
Methane, C_1	0.021
Ethane & Heavier, C_2+	0.000
Hydrogen Sulfide, H_2S	1.333
Carbonyl Sulfide, COS	0.053
Ammonia, NH_3	0.017
Hydrogen Chloride, HCl	0.013
Nitrogen, N_2	0.950
Argon, Ar	0.668
Water, H_2O	18.192
Total Vol%	100.000
Flow Rates:	
Total Lbmoles/Hr	49,318
Total lbs/hr	1,033,000
Temperature, ^oF	1,300 (Norm) 1,350 (Max)
Pressure, psig	500 *

* 550 psig gasifier exit pressure; 50 psi pressure drop allowance for radiant boiler, multi-stage cyclones, convective cooler (if necessary), and other pre-treatment requirements.

Table 3.4
Steam Conditions at Onsite Unit Battery Limits

	Pressure, psig	Temperature, °F
High High Pressure (HHP) Steam:		
SuperHeated (SHHP)		
Generation	1700	1000
Consumption	1700	1000
Saturated (SatHHP)		
Generation	1750	618
Consumption	1750	618
High Pressure (HP) Steam:		
Generation	650	500
Consumption	650	500
Medium Pressure (MP) Steam:		
Super-Heated (SMP)		
Generation	450	1000
Consumption	450	1000
Saturated (SatMP)		
Generation	500	470
Consumption	500	470
Intermediate Pressure (IP) Steam:		
Generation	300	500
Consumption	300	500
Low Pressure (LP) Steam:		
Generation	60	550
Consumption	60	550

Table 3.5
Water Supply & Return Conditions at Onsite Unit Battery Limits

Water Supply at Onsite Unit Battery Limit:

	Pressure, psig	Temperature, ^oF
Boiler Feed Water (BFW):		
HHP BFW	1850	598
HP BFW	750	450
MP BFW	550	450
IP BFW	550	265
LP BFW	550	265
Demineralized Water	80	60
Process Makeup Water	100	60
Cooling Water Supply	70	85

Water Return at Onsite Unit Battery Limit:

	Pressure, psig	Temperature, ^oF
Boiler Blowdowns (a)	30	140
Process Condensates (b)	70	310
Cooling Water Return	40	120 (Max)

Notes:

(a) Assumed Blowdowns will be flashed to LP steam header, and the residual water will be air cooled to 140 ^oF before being pumped offsite for treating.

(b) Assumed all process condensates will be flashed to LP steam header, and the residual water will be pumped offsite for treating.

Table 3.6
Natural Gas Compositions & Properties

Pressure, psig	120	
Temperature, ^oF	60 Min 100 Max	
Gas Analysis, Vol% (a):		
Nitrogen	1.6	
Carbon Dioxide	1.0	
Methane	93.1	
Ethane	3.2	
Propane	0.7	
Butane	0.4	
Pentane	---	
Hexane & Heavier	---	
Total	100.0	
HHV, Btu/SCF (a)	1,032	
LHV, Btu/SCF (a)	932	
H_2S, Grains/100 SCF	0.5	Max
Total Sulfur, Grains/100 SCF	10	Max

Notes:
(a) Natural gas composition, HHV & LHV are from 2004 NETL "Quality Guidelines for Energy System Studies". All other properties are per Nexant in-house data.

Table 3.7
Miscellaneous Utility Commodity Properties

Nitrogen:

Nitrogen for intermittent and shutdown purges are available at the following onsite unit battery limit conditions:

	Pressure, psig	Temperature, °F
High Pressure (HP)	650	100
Medium pressure (LP)	350	100

Oxygen concentration in Nitrogen ranges from 100 ppmv to 1 vol%.

Plant and Instrument Air:

Air	Pressure Psig	Temperature °F	Maximum Dew Point, °F
Plant (oil free)	120	100	Saturated
Instrument (oil free)	90	100	- 40

This section provides an overview of the Reference IGCC conceptual design for Case 1 using coal #1 (2004 NETL coal) and Case 3 using coal #2 (2006 NETL coal). Except for throughputs, the same design concept is applicable to both design Illinois No. 6 coal feeds. The conceptual design is developed with the following features, as desired by RTI:

- 600 MW nominal capacity,
- 1800 ft^3 GE gasifiers operating under radiant-cooling-only mode for waste heat recovery,
- Conventional cryogenic air separation units (ASU), producing 95% purity oxygen (O_2) with no integration to the power train,
- Selexol as the conventional AGR technology,
- Conventional Claus sulfur recovery with SCOT tail gas treating,
- Low-temperature mercury (Hg) removal,
- No CO_2 recovery and no pre-investment for future CO_2 recovery, and
- A combined cycle power plant based on GE 7FB turbine.

4.1 OVERALL BLOCK FLOW DIAGRAM AND MAJOR STREAM FLOWS

Figure 4.1 shows the overall process block flows for the conceptual Base Case Reference IGCC. BOP units are not included in the BFD except for the Combined Cycle Systems. Major stream flows and properties are shown on Table 4.1 for 2004 NETL Illinois #6 coal feed (Case 1), and Table 4.2 for 2006 NETL Illinois #6 coal feed (Case 3) operations.

Figure 4.1
Reference IGCC Overall Process Block Flow Diagram

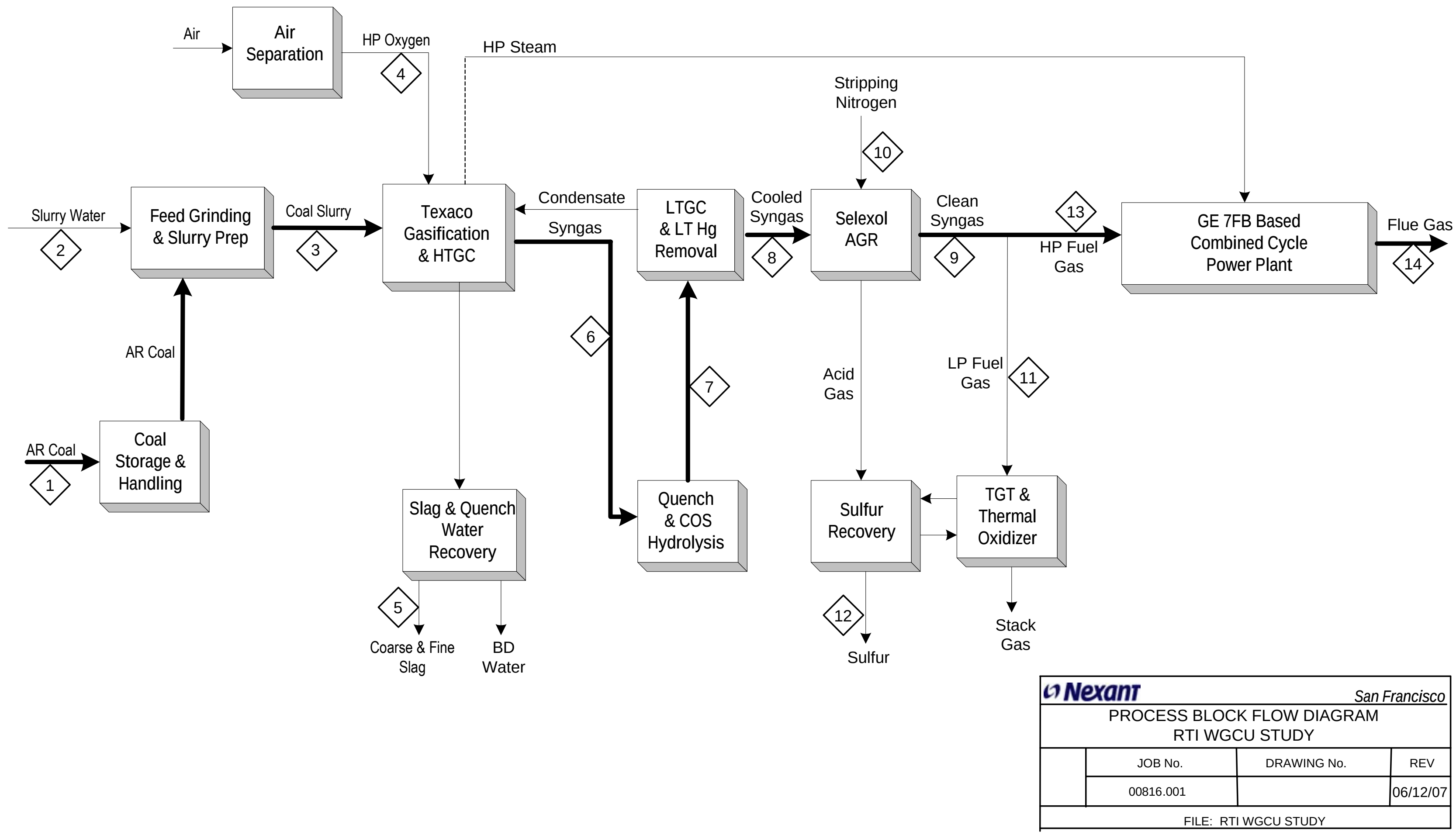


Table 4.1 - Major Stream Flows and Properties for 2004 NETL Illinois #6 Coal

Stream Number			1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.	12.	13.	14.
Stream Description			AR Coal Feed	Make-Up H2O to Slurry Prep	Coal Slurry to Gasifiers	95.00% Oxygen to Texaco Gasific'n	Fines & Slag (Dry Basis)	Cooled Syngas fr Radiant Boiler	Quenched Syngas from Scrubber	Cooled Syngas to AGR	Clean Syngas from AGR	Strip N2 to AGR	LP FG to TGTU Comb & Incin	Molten Sulfur from Claus	Total HP Fuel Gas to Gas Turbine	HRSG Flue Gas Vent to Stack
Pressure, psia			14.7	14.7	664.7	664.7	14.7	544.7	510.7	470.7	430.7	500.7	114.7	14.7	414.7	14.8
Temperature, deg F			60.0	60.0	250	140.0	180.0	1300.0	382.7	90.0	95.0	90.0	95.0	---	95.0	259.4
Flow Rate: MMSCFD Vapor			---	---	---	108.1	---	437.1	591.5	358.3	339.5	2.2	5.5	---	334.0	2,530.0
: STPD Water			459.3	2,602.3	3,061.6	---	---	---	---	---	---	---	---	---	---	---
: STPD Solid (Dry)			5,303.3	---	5,303.3	---	869.7	---	---	---	---	---	---	255.5	---	---
Mass Flow Rate, lb/hr			480,219	216,856	697,075	381,352	72,473	1,005,233	1,310,692	849,368	765,976	6,866	12,328	21,289	753,648	8,137,394
Molecular Weight			---	18.02	---	32.12	---	20.95	20.18	21.59	20.55	28.17	20.55	32.06	20.55	29.30
HHV, Btu/SCF (Btu/LB)			(10,999)	---	(7,577)	0.0	---	---	181.3	266.7	269.6	---	269.6	(4,863)	269.6	2.9
LHV, Btu/SCF (Btu/LB)			(10,558)	---	(7,274)	0.0	---	---	150.1	247.8	250.6	---	250.6	(4,863)	250.6	0.0
Total MMBtu(LHV)/Hr			5,070	0	5,070				3,700	3,699	3,545		57	104	3,487	0
Vapor Composition, Mole %:																
	N2	28.013	---	---	---	2.3%	---	1.0%	0.7%	1.2%	1.3%	98.0%	1.3%	0.0%	1.3%	73.0%
	O2	31.999	---	---	---	95.0%	---	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	12.3%
	CO2	44.010	---	---	---	0.0%	---	13.6%	10.1%	16.7%	13.9%	0.0%	13.9%	0.0%	13.9%	8.0%
	Ar	39.948	---	---	---	2.7%	---	0.7%	0.5%	0.8%	0.9%	1.0%	0.9%	0.0%	0.9%	0.9%
	H2	2.016	---	---	---	0.0%	---	29.2%	21.6%	35.7%	37.6%	0.0%	37.6%	0.0%	37.6%	0.0%
	CO	28.010	---	---	---	0.0%	---	35.9%	26.5%	43.8%	46.1%	0.0%	46.1%	0.0%	46.1%	0.0%
	H2S	34.076	---	---	---	0.0%	---	1.3%	1.0%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	COS	60.070	---	---	---	0.0%	---	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	CH4	16.043	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	C2H6+	30.070	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	SO2	64.059	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Steam	18.016	---	---	---	0.0%	---	18.2%	39.6%	0.1%	0.1%	0.0%	0.1%	0.0%	0.1%	5.9%
Total %			0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%

Table 4.2 - Major Stream Flows and Properties for 2006 NETL Illinois #6 Coal

Stream Number			1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.	12.	13.	14.
Stream Description			AR Coal Feed	Make-Up H2O to Slurry Prep	Coal Slurry to Gasifiers	95.00% Oxygen to Texaco Gasific'n	Fines & Slag (Dry Basis)	Cooled Syngas fr Radiant Boiler	Quenched Syngas from Scrubber	Cooled Syngas to AGR	Clean Syngas from AGR	Strip N2 to AGR	LP FG to TGTU Comb & Incin	Molten Sulfur from Claus	Total HP Fuel Gas to Gas Turbine	HRSG Flue Gas Vent to Stack
Pressure, psia			14.7	14.7	664.7	664.7	14.7	544.7	510.7	470.7	430.7	500.7	114.7	14.7	414.7	14.8
Temperature, deg F			60.0	60.0	250	140.0	180.0	1300.0	372.2	90.0	95.0	90.0	95.0	---	95.0	259.1
Flow Rate: MMSCFD Vapor			---	---	---	110.2	---	435.8	557.0	363.6	353.5	1.2	2.9	---	350.6	2546.8
: BPSD Liquid			608	2,197	2,805	---	---	---	---	---	---	---	---	---	---	---
: STPD Solid			4,859	---	4,859	---	562	---	---	---	---	---	---	136.60	---	---
Mass Flow Rate, lb/hr			455,608	183,106	638,714	388,725	46,801	978,772	1,218,458	835,826	791,415	3,655	6,505	11,383	784,910	8,193,408
Molecular Weight			---	18.02	---	32.12	---	20.45	19.92	20.94	20.39	28.17	20.39	32.06	20.39	29.30
HHV, Btu/SCF (Btu/LB)			(11,666)	---	(8,322)	0.0	---	---	193.3	269.6	271.1	---	271.13	-4862.80	271.13	3.07
LHV, Btu/SCF (Btu/LB)			(11,138)	---	(7,945)	0.0	---	---	163.5	250.4	251.9	---	251.93	-4862.80	251.93	0.00
Total MMBtu(LHV)/Hr			5,075	0	5,075				3,794	3,794	3,711		30.50	55.35	3680.72	0.00
Vapor Composition, Mole %:																
	N2	28.013	---	---	---	2.3%	---	1.0%	0.8%	1.2%	1.3%	98.0%	1.3%	0.0%	1.3%	72.8%
	O2	31.999	---	---	---	95.0%	---	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	11.9%
	CO2	44.010	---	---	---	0.0%	---	12.5%	9.8%	15.0%	13.5%	0.0%	13.5%	0.0%	13.5%	8.3%
	Ar	39.948	---	---	---	2.7%	---	0.7%	0.5%	0.8%	0.8%	1.0%	0.8%	0.0%	0.8%	0.9%
	H2	2.016	---	---	---	0.0%	---	30.8%	24.1%	36.9%	38.0%	0.0%	38.0%	0.0%	38.0%	0.0%
	CO	28.010	---	---	---	0.0%	---	37.5%	29.4%	45.0%	46.2%	0.0%	46.2%	0.0%	46.2%	0.0%
	H2S	34.076	---	---	---	0.0%	---	0.7%	0.6%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	COS	60.070	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	CH4	16.043	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	C2H6+	30.070	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	SO2	64.059	---	---	---	0.0%	---	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Steam	18.016	---	---	---	0.0%	---	16.7%	34.8%	0.1%	0.1%	0.0%	0.1%	0.0%	0.1%	6.1%
Total %			0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%

4.2 PROCESS DESCRIPTION

To meet the required plant capacity of 600 MW (nominal), the Reference IGCC plant would need to process either approximately 5,763 STPD of as-received (AR) 2004 NETL Illinois No. 6 coal, or 5,467 STPD of AR 2006 NETL coal. Table 4.3 lists the number of parallel operating trains needed to process these tonnages of coal.

Table 4.3
Number of Parallel Operating Trains for Reference IGCC Plant

	# Operating + Spare
• Coal Handling & Storage	2 + 0
• GE Gasification & Slurry Preparation	2 + 1
• Air Separation/O_2 Compression	2 + 0
• LTGC/COS Hydrolysis/Hg Removal	2 + 0
• Selexol AGR	2 + 0
• Sour Water Stripping	1 + 0
• Claus Sulfur Recovery	2 + 1
• SCOT Tailgas Treatment	2 + 1
• GE 7FB GT/Generator	2 + 0
• HRSG/Boiler Plt./BFW/Condensate Systems	2 + 0
• Steam Turbine/generator/surface condenser	2 + 0

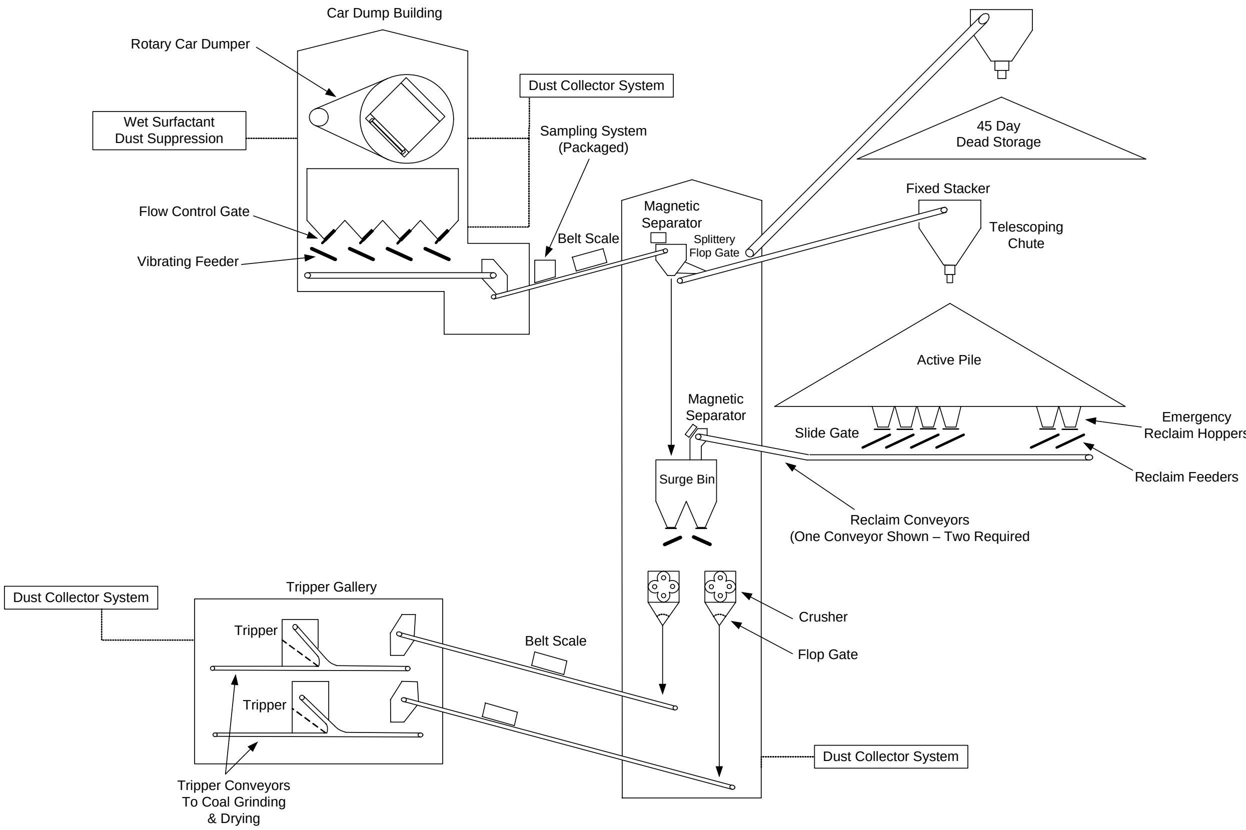
The major systems in the IGCC plant are described below.

4.2.1 Coal Storage and Handling

The coal storage and handling system is designed to receive coal at the battery limits and direct it to either a live or dead storage pile. A common reclaimer and belt conveyor system is normally provided to retrieve the coal and sent it onto a coal storage bin within the Grinding & Slurry Preparation plant. Figure 4.2 shows a simplified flow scheme of the coal storage and handling facility.

A typical coal handling system is designed to handle an active storage pile holding 5 to 8 days of feed, and a dead (long-term) storage pile with capacity up to 30 to 45 days at full load.

Figure 4.2
Simplified Coal Storage and Handling Flow Scheme

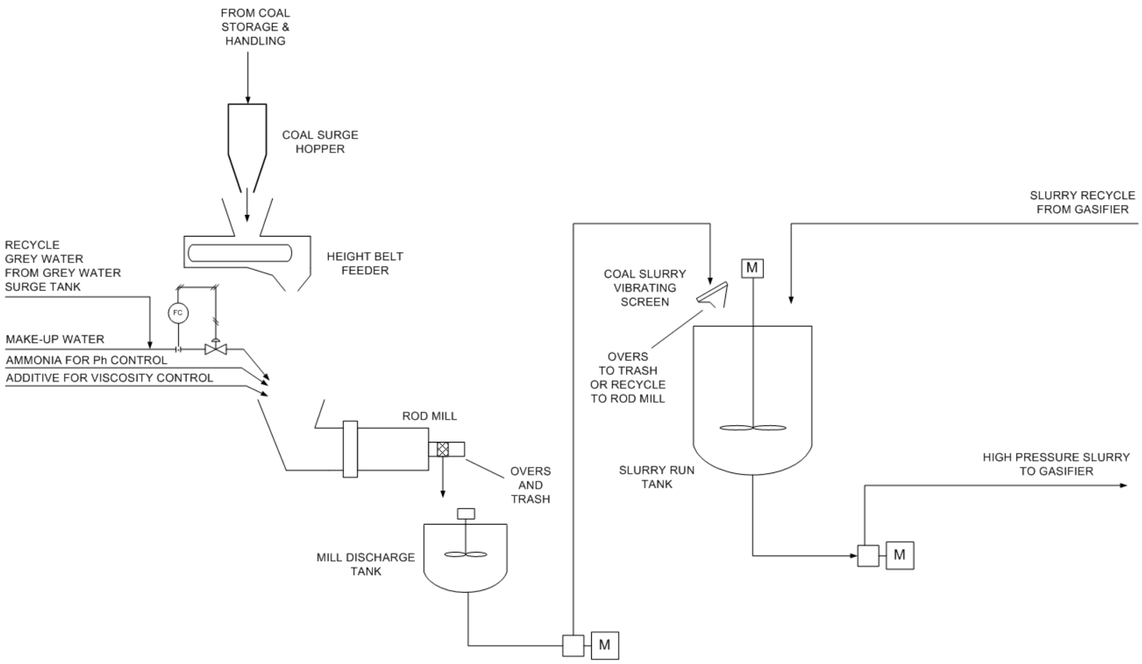


4.2.2 Grinding & Slurry Preparation

The GE gasification process uses coal slurry feed. Design of the grinding and slurry preparation plant has major impact on the entire gasification facility. The maximum coal slurry concentration that can be pumped is a critical design parameter that affects the gasifier unit capacity, oxygen consumption and other related utility consumptions.

The grinding mills (typically either ball or rod type) reduce the nominal 2” x 0” feed coal to a design particle size distribution, in the presence of a preset flow of slurry feed water with viscosity and pH additives. The produced slurry, after removal of the oversize material, which is normally recycled to the mill, is pumped to the gasification plant. Typical coal slurry feed to the GE gasifier contains approximately 63% of coal by weight.

Figure 4.3
Simplified Coal Grinding and Slurry Preparation Scheme



4.2.3 GE Coal Gasification, Slag Removal and Wet Scrubbing

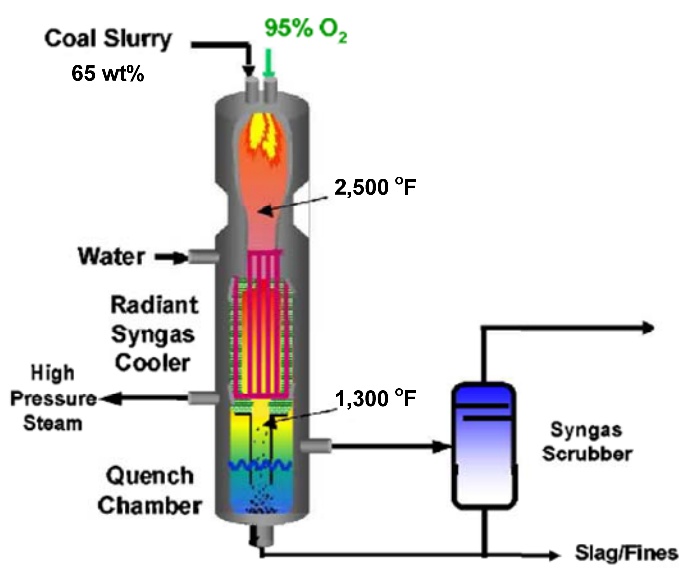
The GE gasifier is a slurry-feed pressurized entrained flow reactor with a low residence time. It is a non-catalytic process involving the reaction of hydrocarbon materials with oxygen at high temperature and pressure under conditions of insufficient oxygen for complete combustion (partial oxidation). The partial oxidation produces a gaseous product (syngas) consisting primarily of hydrogen and carbon monoxide with lesser amounts of water vapor, carbon dioxide, hydrogen sulfide, methane, and nitrogen. Traces of carbonyl sulfide and ammonia are also formed. The high temperature eliminates formation of tars, phenols, or other hydrocarbons. Ash from the feed is melted to form a glassy slag.

The process consists of feeding coal slurry into the gasifiers through special burners where it is mixed with oxygen supplied by the air separation plant at 95 mole% purity. The coal slurry is pumped at high pressure from the slurry charging pumps to the water-cooled gasifier burners on top of the refractory-lined combustion section of the gasifier. In the gasifiers, the coal is partially combusted to form the raw syngas. The gasifiers operate normally at a temperature around 2400 to 2700 ^{o}F, depending on the ash fusion characteristics of the coal. The raw syngas, slag and unconverted carbon flow downward into the radiant syngas cooler, where they are cooled to about 1300 ^{o}F. High pressure steam is made by circulating boiling feed water through the radiant syngas cooler, and is sent to the heat recovery steam generator (HRSG) unit within the combined cycle plant for superheating and subsequent power generation. Most of the solids exiting the radiant syngas cooler drop into the water pool at the bottom of gasifier where they are quenched and solidified as slag. The solidified slag is removed from the gasifier bottom by means of lock hoppers, and is dewatered and sent to disposal. Raw syngas and the remaining entrained solids exist the radiant cooler through a crossover duct, is scrubbed by water contact via a high efficiency nozzle-type scrubbing device to remove all the entrained particulate. The scrubbing system also removes other minor contaminants such as soluble alkali salts and hydrogen halides. The particulate-free syngas is routed to the low temperature gas cooling section.

Figure 4.4 shows a simple schematic of a GE gasifier operating under a radiant-cooling-only mode condition.

The scrubbing water and the water from the gasifier slag quench contain soot. They are let down in pressure (flash) and then sent to a clarifier. A small flash gas stream containing trace amount of H_2S and NH_3 is routed to the sulfur recovery unit and thermal oxidizer in the tail gas treating plant. The clarifier overflow is recycled to the scrubbing unit, and highly concentrated solids from the clarifier bottoms are recycled to the coal grinding plant. A purge stream is taken from the clarifier to prevent buildup of solids and contaminants in the system. Process waste water is sent to the sour water stripper plant for treatment.

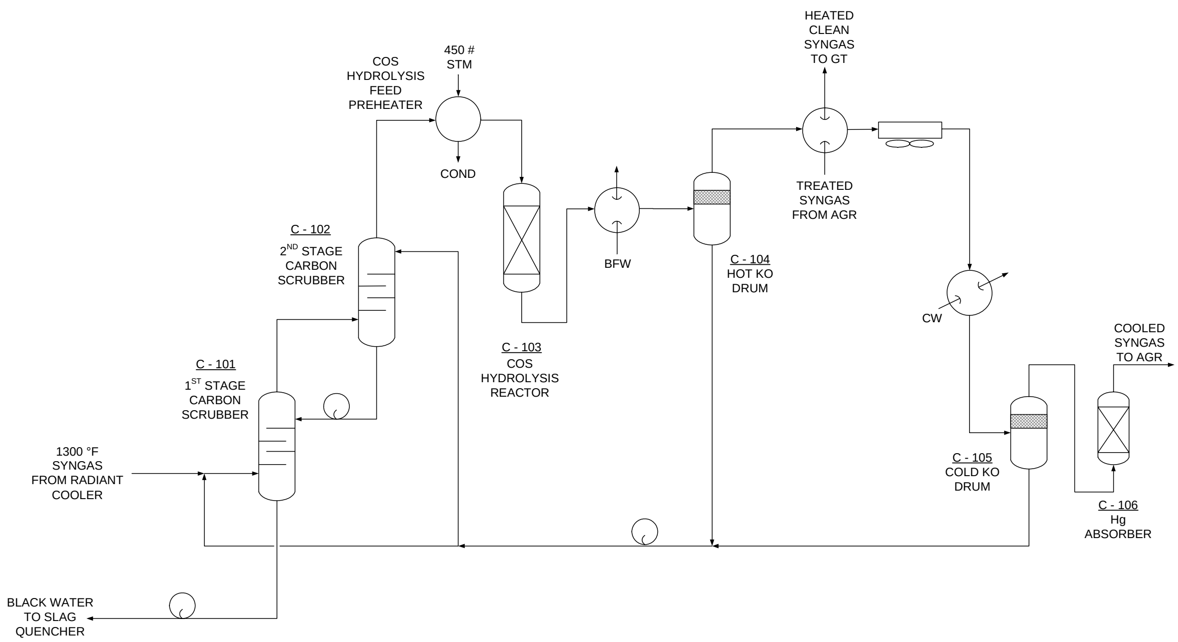
Figure 4.4
Simplified Drawing of a GE Gasifier designed for Radiant-cooling-only Operation



4.2.4 Low Temperature Gas Cooling (LTGC)

The scrubbed gas entering into LTGC unit is at a higher temperature and carries moisture. It is heated with 650 psig HP steam to 50 ^{o}F above saturation before going through the COS hydrolysis reactor to convert most of the COS into H_2S to allow the downstream AGR (Selexol) plant to meet total sulfur removal specifications. The COS hydrolysis reactor effluent is cooled to approximately 100 ^{o}F before sent onto the Hg absorber to remove 90% of its mercury. The effluent is then sent to the AGR plant (Selexol) for H_2S removal. Figure 4.5 is a simple schematic of a COS Hydrolysis/LTGC system.

Figure 4.5
Simplified COS Hydrolysis/LTGC Flow Scheme



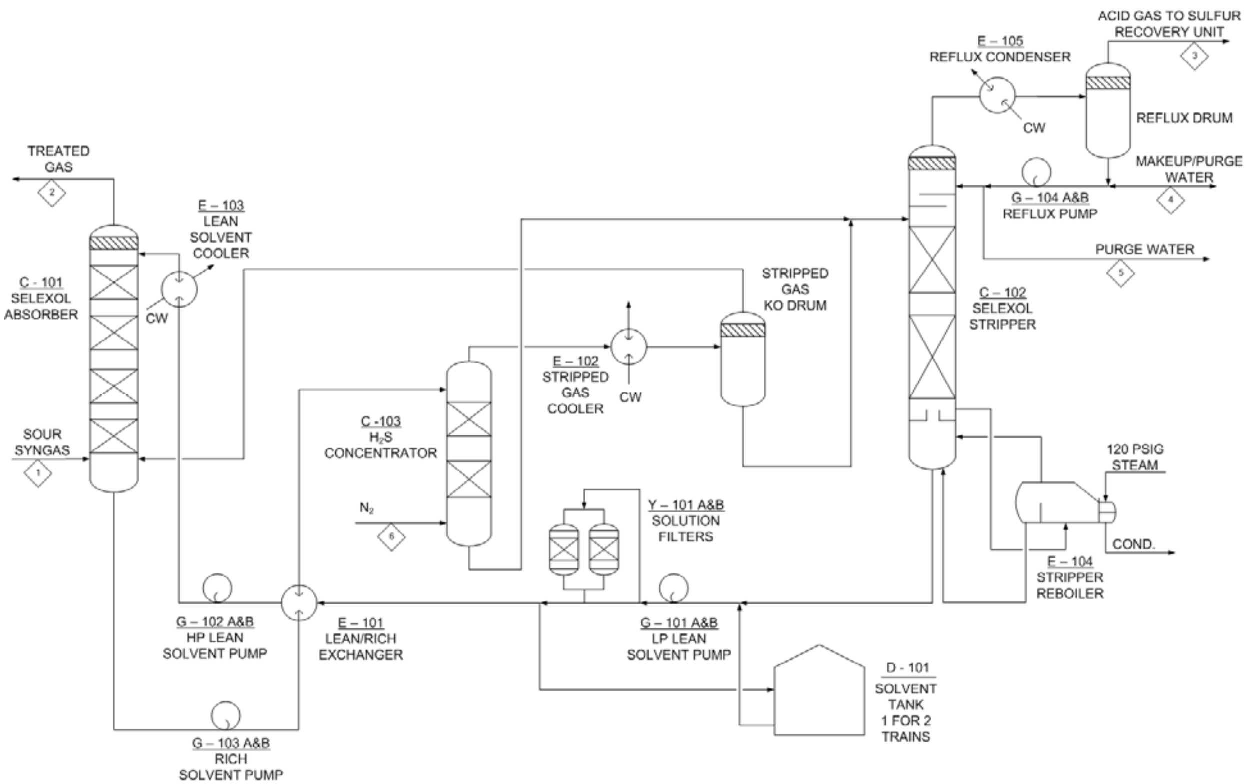
4.2.5 Acid Gas Removal of Selexol

Selexol is chosen for the study as the commercially available AGR process for IGCC. The technology was originally developed by Allied Chemicals, and is now owned by UOP. The Selexol process has been in commercial use for over 30 years to remove acid gas from natural gas streams. There are currently more than 50 units in commercial service, and the technology has been selected for several IGCC projects that are under development. UOP has assisted Nexant with providing a design and performance information based on a given raw syngas feed to the plant.

Figure 4.6 shows a typical flow scheme of a Selexol process, exhibiting the typical characteristics of most physical (or chemical) solvent absorption systems. Acid gas of H_2S and CO_2 are absorbed from the raw syngas, under high partial pressure, in the Selexol absorber and the solvent is thermally regenerated in the stripper. The process can selectively remove H_2S from

CO_2, and it also removes COS, mercaptans, ammonia, and other metal carbonyls. The solvent used is dimethyl ethers of polyethylene glycol (DMPEG).

Figure 4.6
Typical Selexol Flow Scheme



4.2.6 Sulfur Recovery and Tail Gas Treating

Acid gas from the Selexol unit, the sour water stripper (SWS) and various miscellaneous sour LP purge streams are processed in the Claus SRU to convert and recover about 96% of the sulfur species as elemental sulfur byproduct. Claus SRU offgas is sent to the SCOT tail gas treating unit (TGTU) where 80 to 90% of the un-reacted sulfur is recovered for recycle back to the Claus SRU. Net sulfur recovery by the Claus SRU/SCOT TGTU is expected to exceed 99% of the sulfur in the feeds.

4.2.6.1 Claus SRU

A 3-stage split-flow Claus SRU is provided to recover sulfur from the low H_2S content (less than 30% by volume) acid gas from Selexol AGR. Figure 4.7 is a simplified flow scheme of the 3-stage split-flow Claus SRU.

The Claus reaction consists of:

$$\text{Combustion:} \quad 1\ H_2S + 1.5\ O_2 \rightarrow 1\ SO_2 + 1\ H_2O$$

$$\underline{\text{Catalytic Conversion:} \quad 2\ H_2S + 1\ SO_2 \rightarrow 3\ S + 2\ H_2O}$$

$$\text{Overall:} \quad 3\ H_2S + 1.5\ O_2 \rightarrow 3\ S + 3\ H_2O$$

Acid gas from the SWS plus part of the acid gas from the Selexol is burned with sufficient air to produce an overall SRU feed with the desired 2 to 1 stoichiometric ratio of H_2S to SO_2 for conversion to sulfur and water. The hot burner exhaust is cooled in the waste heat boiler (WHB) before being mixed with the remaining Selexol acid gas prior to entering the first stage catalytic converter. Approximately 75% of the sulfur conversion occurs in the 1st stage catalytic converter. The remaining sulfur species in the 1st stage catalytic converter exhaust are converted in subsequent catalytic converters. Reaction heat produced in the burner is recovered in the integrated WHB by generating 650 psig steam.

Sulfur products are cooled and condensed by generating low pressure steam. Condensed sulfur product is stored in an underground molten sulfur pit, where it is later pumped to truck loading for shipment. Claus tail gas from the last stage sulfur condenser is sent to SCOT TGTU to remove unconverted H_2S, SO_2, and COS before disposal.

4.2.6.2 SCOT TGTU

Figure 4.8 is a simplified flow scheme for a typical SCOT TGTU.

Tail gas from the Claus SRU is heated in an in-line burner before entering the COS hydrolysis reactor, where COS is converted to H_2S and water. After the addition of some reducing gas, effluent from the hydrolysis reactor then goes to the hydrogenation reactor, where SO_2 is converted to H_2S and water. Hydrogenation reactor effluent is then cooled by generating LP steam followed by cooling with CW. Residual H_2S in the cooled tailgas is removed with amine in a counter-current packed absorber. The treated tail gas from the absorber top is incinerated before vent to atmosphere.

The rich solvent from the amine absorber is pumped to the regenerator after heat exchanged against the hot lean solvent from the regenerator. Acid gases are stripped from the solvent in the trayed regenerator via steam reboiler. The hot lean solvent from the regenerator bottom is pumped back to the absorber after cooling by heat exchange against rich solvent and by cooling water. Acid gas from TGTU amine regenerator overhead is recycled back to the Claus plant for sulfur recovery.

Figure 4.7
Typical 3-Stage Split-Flow Claus Sulfur Recovery Flow Scheme

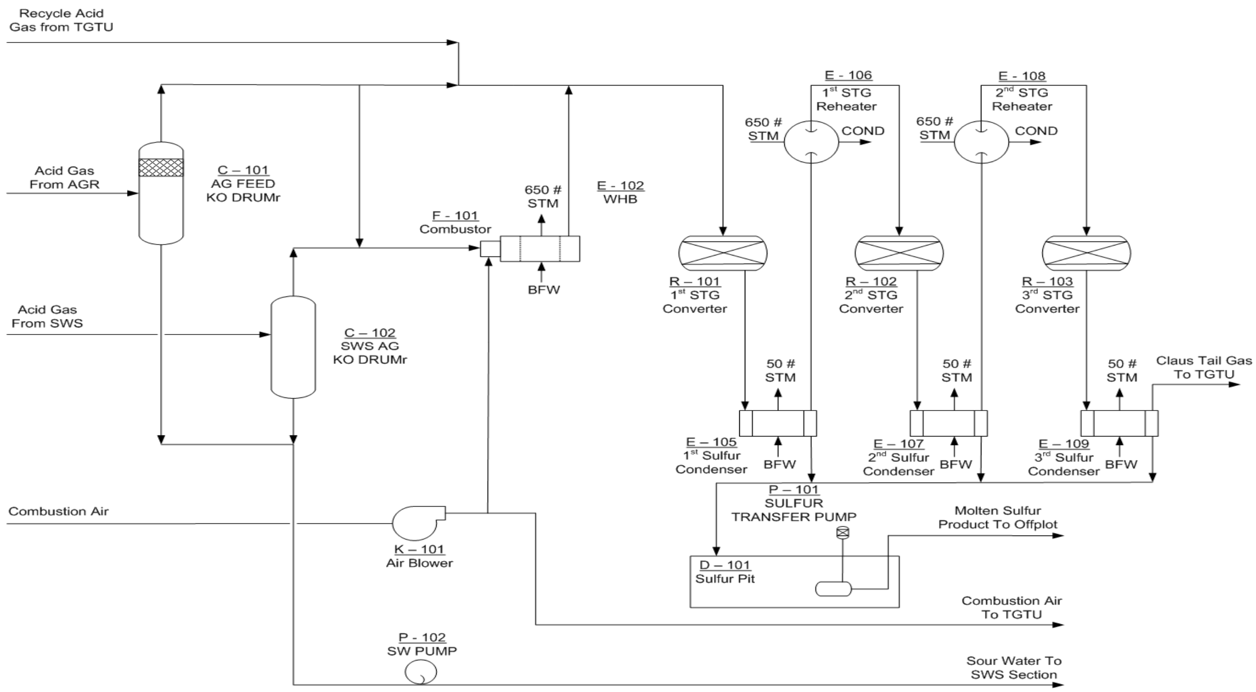
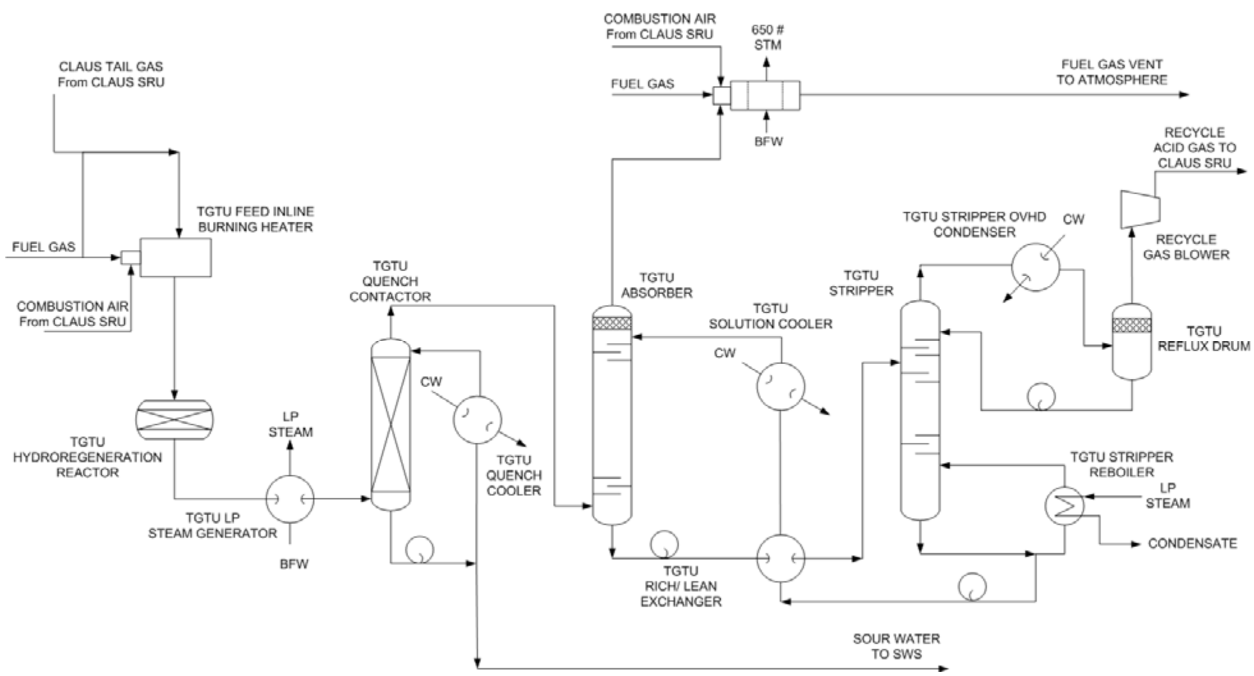


Figure 4.8
Typical TGTU Flow Scheme



4.2.7 Air Separation and Oxygen Compression

The air separation unit supplies high-pressure oxygen to the gasifier. It also provides nitrogen and backup plant air for the acid gas removal and other plant services.

Conventional cryogenic Air Separation Unit (ASU) uses ambient air, without air extraction from the GT, to produce a 95% purity oxygen stream for gasification, and in the case of WGCU, additional amount of oxygen to meet the WGCU ZnS-to-ZnO regeneration requirement. The O_2 will be compressed and cooled before being delivered to the gasification battery limit (B/L). Liquid N_2 and O_2 storage and vaporization facilities are included to ensure high availability without the need for a spare ASU train.

Figure 4.9 shows a typical simplified flow scheme for cryogenic ASU. Ambient air is filtered of particulate matter in the inlet air filter and compressed by the air compressor. The heat of compression is removed in the two inter-stage cooler. In the first stage of this cooler the air is cooled against plant cooling water. In the second stage, air is cooled against chilled water.

After exiting the direct contact air cooler, the air stream enter the molecular sieve adsorber, which removes water, carbon dioxide, and heavy hydrocarbons from the air stream in preparation for cryogenic processing.

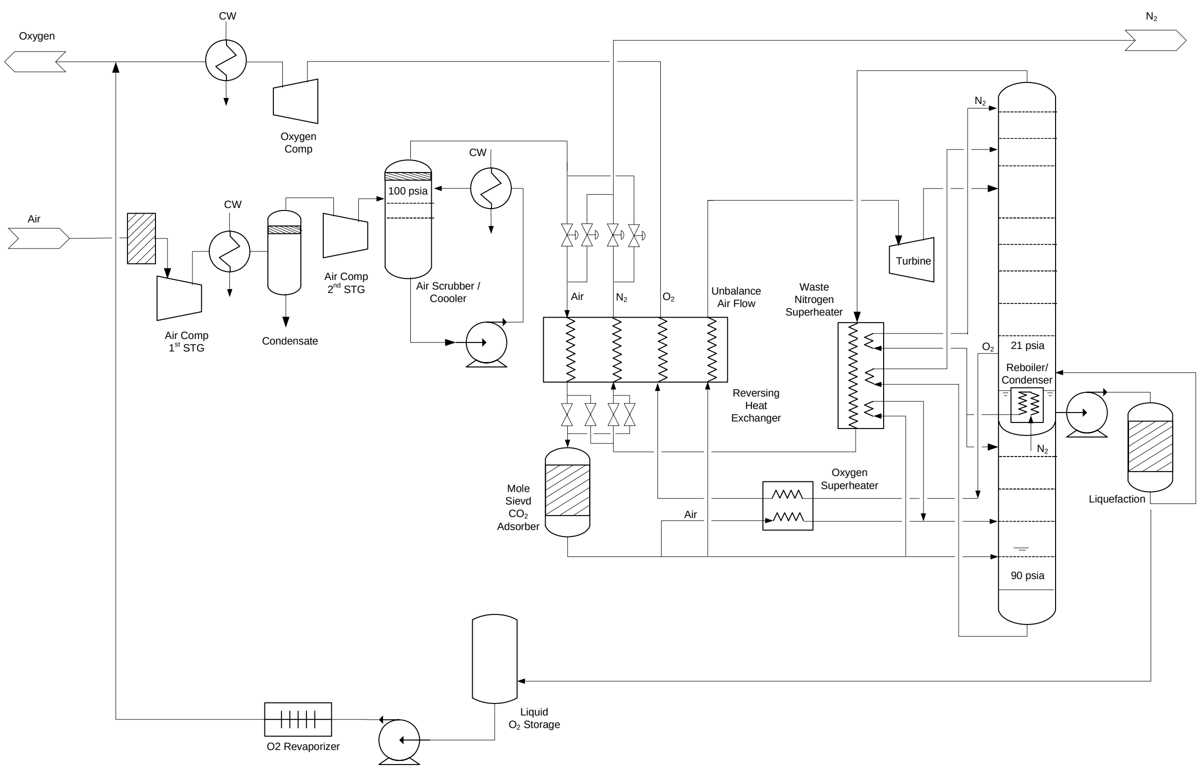
The molecular sieve adsorber consists of multiple horizontal, externally insulated vessels operated with one bed on stream while the other bed is being regenerated. The molecular sieve adsorber is regenerated using heated waste nitrogen gas from the cold box. Waste nitrogen is heated by the regeneration steam heater.

Gaseous oxygen product delivered from the coldbox is further compressed in the booster oxygen compressor before it is delivered to the high pressure gasifiers.

Gaseous nitrogen from ASU is compressed in the BOP N_2/Instrument Air/Plant Air system and delivered at two pressure levels:

- 350 psig for use as NOx diluent to the GT, and
- 600 psig for use as emergency purge nitrogen to the gasification system; as stripping nitrogen to the Selexol AGR; or as fluidization nitrogen to the WGCU regenerator.

Figure 4.9
A Typical Air Separation / O2 Compression Flow Scheme



4.2.8 Gas Turbine Combined Cycle (GTCC) Power Plant

The combined cycle power plant is based on two General Electric's 7FB (GE 7FB) advance gas turbine (GT), modified to burn clean syngas to make power. Each GT is equipped with its own HRSG to recover waste heat from the hot GT exhausts. Two steam turbine generators are included to complete the two 50% GTCC trains arrangement for optimum overall availability. Figure 4.10 is a simplified GTCC flow scheme.

Each GE 7FB GT has a gross output of approximately 230 MW. The following syngas firing characteristics from GE publications are used to estimate the 7 FB performances:

- Turbine exhaust gas temp, °F — 1,050 Min; 1,150 Max
- Air flow rate, lb/sec — 950
- Compression ratio — 18.5
- Air compressor polytropic efficiency — 92 % (assumed)
- Turbine polytropic efficiency — 87.5 % (assumed)
- Generator conversion efficiency — 99 % (assumed)

Two un-fired three pressure level HRSG are used to recover waste heat from the GT exhaust. The HRSG generate 1700 psig/1000°F superheated HHP steam, 450 psig/1000°F reheated MP steam, and 60 psig/550°F LP steam for use for power generation by the STG, and to meet process plant steam demands. Saturated 1,700 psig steam from the gasification radiant cooler is routed to the HRSG for superheating to 1,000°F before feeding into the STG for power generation.

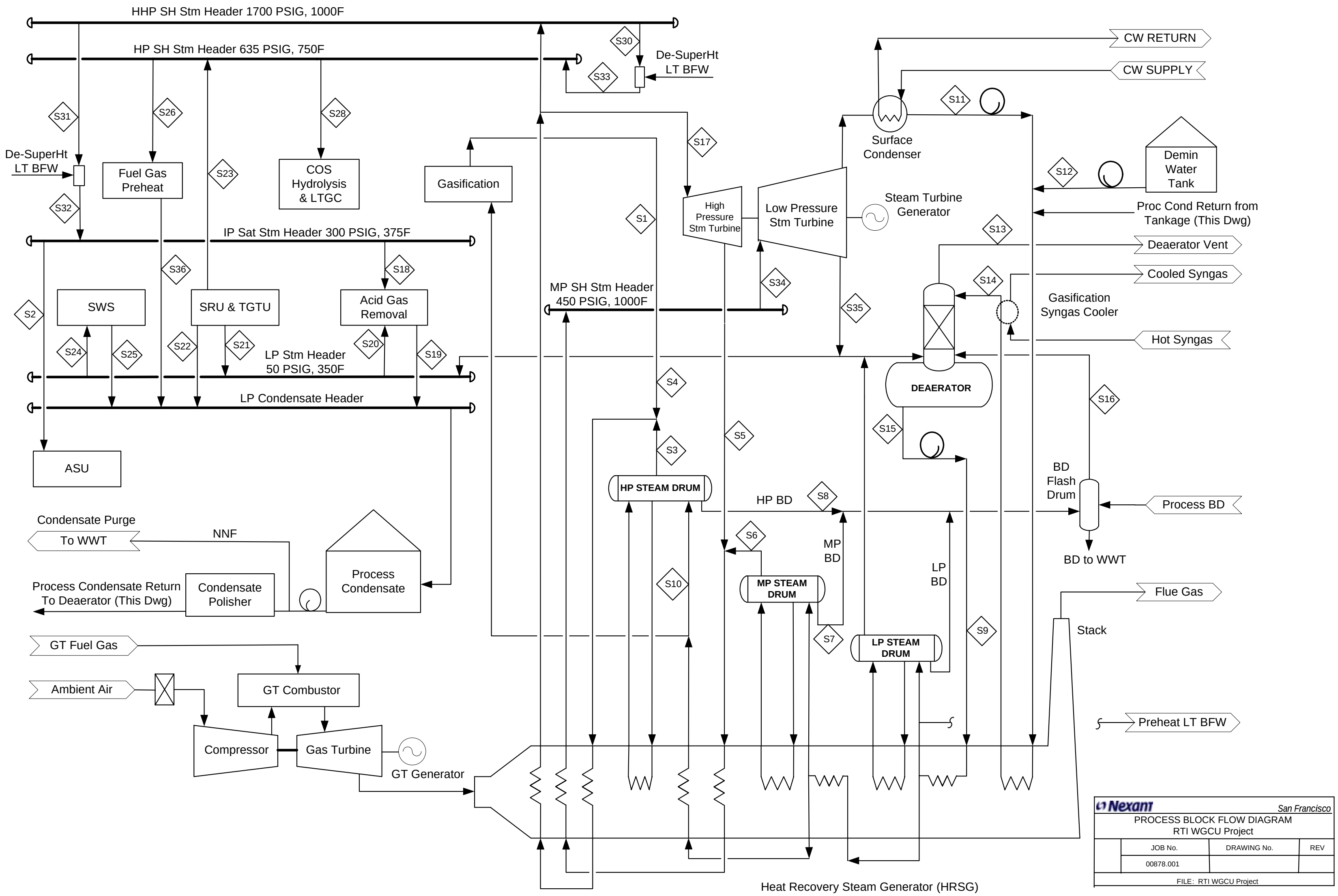
650 psig 500°F saturated HP steam and 300 psig 500°F superheated IP steam headers are included to meet process steam generation and consumption needs.

The HRSG system includes the steam drums, BFW pumps, and deaerators.

Two reheat condensing steam turbine generators (STG) are included to convert the superheated steam into power. Based on simple availability analysis, two STG are provided in order to meet the required 85% onstream factor.

N_2 injection is included in the Reference IGCC Plant design to lower the GT fuel gas LHV down to about 160 Btu/SCF after mixing with injection N_2. The GT are equipped with low NOx burners so that the Reference IGCC plants can meet 15 ppm NOx emission without the need of SCR.

Figure 4. 10
Simplified Gas Turbine Combined Cycle (GTCC) Power Plant Flow Scheme



4.2.9 Balance of Plant Facilities

In addition to the above major process units, the IGCC plant is supported with the following offsite facilities:

4.2.9.1 Coal Storage and Handling Facilities

See Section 4.4.1 for details.

4.2.9.2 Relief and Flares System

The relief and blowdown system consists of:

- Hydrocarbon flares and main relief headers > 48” with dedicated liquid knockout drum and liquid drain pumps
- A H_2S flare and its H_2S relief header with its own liquid knockout drum and liquid drain pumps

The elevated hydrocarbon flares will handle reliefs from all process units except Selexol, Sour Water and SRU/TGTU plants. Low pressure steam will be injected to produce a smokeless flame for relief loads less than 10% of design.

The elevated H_2S flare will handle reliefs containing H_2S from the Selexol, Sour Water, and SRU/TGTU plants. LP fuel gas, backup with natural gas, is injected to obtain a 1,400°F flame temperature to ensure combustion of the H_2S relief streams.

4.2.9.3 Inter-Connecting Piping System

Inter-connecting piping system includes the off-plot pipeway piping, and off-sites and utility piping outside of the process units. All piping connections inside process units are included in the associated process unit costs. All above ground and underground piping systems are included except that relief headers are part of Relief and Flare system, and fire water mains are part of the fire protection system. In general, drainage and sewer systems are underground, cooling water mains and piping in tankage area are in pipe trenches and all other piping is located above ground on pipe racks.

4.2.9.4 Steam Collection and Distribution System

The steam and condensate collection and distribution system collects and distributes steam to users and recovers steam condensate as the primary water makeup for the boiler feed water deaerators. Blowdowns from boilers are flashed and the low pressure flashed steam is recovered. The flashed liquid is collected and sent to waste water treatment.

4.2.9.5 Plant and Instrument Air System

Plant and instrument air system supplies instrument air, plant air and nitrogen to the process plants and support facilities. Filtered atmospheric air is compressed to 140 psig and cooled to 100 °F before discharging to the plant air header. Part of the compressed and cooled air stream is dried to –40 °F dew point to supply instrument air. A liquid nitrogen pump and vaporizer system is also included to supply pressurized nitrogen to meet the gasification, AGR, sulfur recovery unit, and GT diluent injection demands. Nitrogen is also used as backup supply for the instrument air. N_2 is either trucked in or supplied from the Air Separation Plant.

4.2.9.6 Solid Waste Disposal System

Overland conveyor is included to convey the gasifier slag to disposal facility outside the plant fence. Onsite storage, reclaim and truck removal facilities are provided to remove all slag produced when the overland conveyor is under repair for approximately 10% of the time.

4.2.9.7 Raw/Plant/Potable Water Systems

Plant water supply is assumed from either onsite wells or a river stream. It will provide the makeup water for the steam boilers, the cooling tower, general plant water consumption, and potable water supply. Water for cooling tower makeup, general plant usages and potable uses requires only filtration. Additional treatment for boiler feed water makeup consists of demineralization.

4.2.9.8 Boiler Feed Water (BFW) Makeup (Demineralization) and Condensate Treating Systems

The boiler makeup demineralizer system consists of three cation and anion exchanger trains. Each train is designed to produce 50% of the boiler feed water makeup requirements. The standby train will be put into service when one train is in regeneration. Water from the two bed demineralization system is combined with returned steam condensate to be further treated in a mixed bed ion exchange system to achieve the 1700 psig boiler water requirements. Deminerilizer regeneration wastes are neutralized before send to waste water treating.

4.2.9.9 Sour and Waste Water Treatment Systems

A sour water stripping (SWS) system handles the sour water discharged from the gray water processing section of the gasification unit, excess sour condensate from the low temperature gas cooling (LTGC) unit, and sour water from the tail gas treating unit (TGTU) area. The SWS system consists of a single column steam reboiled sour water stripper with air cooled overhead condenser. The sour water feed is first degassed before it is stored in a 12-hr atmospheric sour water storage tank.

In addition to the SWS system, the following wastewater treatment facilities are included for overall plant wastewater processing

- Contaminated storm water retention
- Wastewater treating
- Biological treatment and solids removal
- Mixing and Disposal

4.2.9.10 Cooling Water System

A closed-loop cooling water (CW) system is provided to cool process streams to temperatures between 90°F and 140°F (i.e., lower than what can be attained with air cooling). Overall plant cooling water loads are presented in Table 8-1 of Section 8.4. The CW system consists of cooling towers with basin, CW circulation pumps, chemical injection facilities, and CW distribution and collection headers. For cost estimation, the CW distribution and collection headers costs are included in the interconnecting piping system.

4.2.9.11 Fire Protection System

Capital cost allowance is included for the general fire protection of the entire plant. Fire protection systems include the following specific facilities and equipment:

- Fire water to process plants, co-generation, coal handling, water and waste treatment, cooling towers (if constructed with wood), and storage tankage
- Fireproofing for vessel supports, pipe racks, etc.
- Water sprinkler systems for buildings. Foam spray system for tank truck filling racks
- Portable extinguishers and mobile foam fire trucks
- Fixed water/foam system on tankage
- Gaseous clean-agent system for control building and laboratory
- Nitrogen system for sulfur storage tank

4.2.9.12 Electrical Distribution System

The electrical distribution system includes power supply lines connecting to the offsite power grid (close by the plant fence), as well as onsite power generation, onsite substations and switchyards, high/medium/low voltage power distribution system throughout the facility.

4.2.9.13 Buildings

Capital cost allowance for the following buildings is included:

- Administration building
- Central control room
- Laboratory building
- Warehouse and maintenance shops
- Fire station
- Guard houses
- Weigh station
- STG building
- Fire water and cooling water pump houses
- Water treatment buildings

4.2.9.14 Communication and Distributive Control Systems

Capital cost allowance is included for distributed control system (DCS) for the remote control and supervision of electronic field instruments and linking onsite/offsite DCS I/Os, process monitors and controllers to the central control room, and the overall telecommunication system for linking plant-wide communications and data processing systems.

4.2.9.15 Rail Car Loading System

Rail car loading system includes allowance for up to fifty thousand (50,000) feet of on-site rail tracks to be shared by the coal receiving, chemical receiving, and slag byproduct off-loading systems.

4.2.9.16 Site Preparation

Capital cost allowance is included to cover the following site preparation activities:

- Leveling approximately 100 acres of area
- Clearing of trees, vegetation, brush, down timber, and rubbish
- Adding basic improvements such as roads, fencing and drainage needed by the plant as a whole
- Placing load-bearing concrete pier and spread footing foundations for the plant structures in accordance with individual needs.

4.3 OVERALL PLANT PERFORMANCE SUMMARY

Table 4.4 shows a summary of the estimated feeds and products for Case 1 and Case 3 Reference IGCC design, feeding 2004 NETL and 2006 NETL Illinois No. 6 coals, respectively. Coal feed processed is based on a constant gasifier residence time of 5 seconds at 550 psig and 2450 ^{o}F exit conditions. The large difference in raw water consumption and waste water production for Case 3 is due to its larger chloride purge requirement.

Table 4.4
Reference IGCC Plant Overall Imports and Exports
(Excluding Chemicals and Catalysts)

	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
CONSUMABLES:		
AR Coal Feed, STPD	5,763	5,467
Raw Water, GPM	4,227	5,646
95.0% O2, STPD	4,576	4,665
99% N2, STPD	6,765	7,024
NG Import, MMBtuLHV/Hr	0	0
PRODUCTS:		
Power Export, MWe	558	585
Sulfur, STPD	255	137
Slag & Ash, STPD Dry	870	562
Waste Water, GPM	1,306	2,798
Recovered CO2, STPD	(0)	(0)
OVERALL ELECTRIC EFFICIENCIES:		
Gross Heating Value Basis	36.1 % HHV	37.6 % HHV
Net Heating Value Basis	37.6 % LHV	39.3 % LHV

4.4 OVERALL MATERIAL BALANCE

Table 4.5 shows the estimated overall process mass balance for the Case 1 and Case 3 Reference IGCC plant.

Table 4.5
Reference IGCC Plant Overall Mass Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVERALL PROCESS MASS BAL, LB/HR:	IN	OUT	IN	OUT
AR Coal Feed	480,219	0	455,608	0
Slurry Water	216,856	0	183,106	0
O2 to Gasifier	381,352	0	388,725	0
Slag/Ash to Disposal	0	152,206	0	98,290
Gasifier MU H2O	526,431	0	1,161,284	0
Gasifier Purge H2O	0	141,241	0	870,109
HCL Removed	0	247	0	1,546
LTGC Condensate	0	461,324	0	382,632
RTI Fluidization N2	---	---	---	---
AGR Strip N2	6,866	0	3,655	0
AGR MUW	3,054	0	1,625	0
Treated Syngas from AGR	0	765,976	0	791,415
AGR H2O Purge	0	1,436	0	788
Fuel Gas to TGTU	12,328	0	6,505	0
Comb Air to SRU/TGTU	99,133	0	53,130	0
Sulfur Product	0	21,289	0	11,383
TGTU Incin Exhaust	0	180,892	0	96,791
TGTU Sour Condensate	0	1,617	0	837
Treated Syngas to GTCC	753,648	0	784,910	0
Suppl't NG to GTCC	0	0	0	0
Comb Air to GTCC	6,826,846	0	6,826,846	0
NOx N2 to GTCC	556,890	0	581,641	0
GTCC HRSG Exhaust	0	8,137,394	0	8,193,408
Total Process Mass Balance, LB/Hr	9,863,623	9,863,622	10,447,035	10,447,199

4.5 REFERENCE IGCC PLANT OVERALL CARBON BALANCE

Table 4.6 shows the estimated overall carbon balance for the Case 1 and Case 3 Reference IGCC plants.

Table 4.6
Reference IGCC Plant Overall Carbon Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVERALL CARBON BAL, LB/HR	IN	OUT	IN	OUT
Coal Feed	290,137	0	290,426	0
Carbon In Slag	0	2,318	0	1,497
Carbon In Ash	0	1,742	0	1,125
Vacuum Flash Sour Gas To SRU	0	108	0	108
Air To GT Air Compressor	844	0	844	0
Acid Gas To SRU	0	17,089	0	9,096
Syngas Loss To AGR CO2	0	0	0	0
HRSG Vent	0	265,396	0	277,154
Other Furnace Exhaust	0	4,328	0	2,290
TOTAL CARBON, LB/HR	290,985	290,985	291,272	291,272

4.6 OVERALL SULFUR BALANCE

Table 4.7 shows the overall process sulfur balance for the two IGCC reference plants. Depending on the coal properties, approximately 5% of the sulfur in the coal feed could be left in the slag and ashes as inert SO_4 solids. For this study, all (i.e., 100%) of the sulfur in the coal feed is assumed to be converted to H_2S and COS in the syngas, within in the gasification unit. Syngas sulfur recovery in the downstream AGR and SRU/TGTU exceeds 99%+.

Table 4.7
Reference IGCC Plant Overall Sulfur Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVERALL SULFUR BAL, LB/HR:	IN	OUT	IN	OUT
Coal Feed	21,346	0	11,419	0
Slag and Fine Ash	0	0	0	0
Sulfur Product from SRU	0	21,289	0	11,383
TGTU Incinerator Vent	0	43	0	23
GTCC HRSG Exhaust	0	14	0	13
Total Sulfur, LB/Hr	21,346	21,346	11,419	11,419

4.7 REFERENCE IGCC PLANT OVERALL STEAM BALANCE

Tables 4.8 to 4.12 show the overall steam balances for the proposed IGCC plants.

Table 4.8 lists the overall HHP steam balance for Case 1 and Case 3. HHP steam from gasification is sent saturated to the HRSG where it is superheated to 1000 ^{o}F for power generation in the steam turbine generator. Letdowns to HP and IP steam headers are provided to meet those header's demands.

Table 4.8
Overall High High Pressure (Nominal 1700 psig 1000 °F) Steam Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
HHP Steam, 1700 PSIG, 1000F:				
Gasification	930	0	914	0
HRSG	424	0	546	0
HP Stm Turbine Feed		1,354	0	1,428
HHP Stm Letdown to HP Stm	0	0	0	19
HHP Stm Letdown to IP Stm	0	0	0	12
TOTAL HHP STEAM, LB/Hr	1,354	1,354	1,460	1,460

Table 4.9 lists the overall HP steam balance for Case 1 and Case 3. In Case 1, the AGR/SRU/TGTU system generates roughly twice as much HP steam as Case 3 because its coal sulfur content is twice that of the Case 3 coal. This additional HP steam production eliminated the need of HHP steam letdown for overall plant steam balance in Case 1. In fact, Case 1 is able to letdown 22,000 LB/Hr of excess HP steam to meet the IP steam demands. Case 3 requires 19,000 LB/Hr of letdown from the HHP steam header in order to meet HP steam demands. This 19,000 LB/Hr HHP steam letdown is equivalent to a 1.3% decrease in the STG steam flow which results in a power output loss of about 3.5 MWe for Case 3 because of its lower sulfur feed.

Table 4.9
Overall High Pressure (Nominal 650 psig 500 °F) Steam Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
HP Steam, 650 PSIG, 500F:				
COS Hydroly, Shift & LTGC	0	36	0	33
GT Fuel Gas Preheater	0	42	0	44
AGR/SRU/TGTU Generation	99	0	53	0
AGR/SRU/TGTU Consumption	0	0	0	0
Letdown from HHP Stm	0	0	19	0
Let down to IP Stm	0	21	0	0
Letdown Desuperheat	0	0	5	0
TOTAL HP STEAM, LB/Hr	99	99	78	78

Table 4.10 shows the overall MP steam balance for Case 1 and Case 3.

Table 4.10
Overall Medium Pressure (Nominal 450 psig 1000 °F) Steam Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
MP Steam, 450PSIG, 1000F:				
HP Stm Turbine Exhaust	1,354	0	1,428	0
HRSG	79	0	57	0
MP Stm Turbine Feed	0	1,433	0	1,485
TOTAL MP STEAM, LB/Hr	1,433	1,433	1,485	1,485

Table 4.11 shows the overall IP steam balance for Case 1 and Case 3. Case 1 is able to meet the ASU IP steam demand with excess HP steam generated from TGTU, while Case 3 requires 12,000 LB/Hr HHP letdown in order to meet IP steam demands. The 12,000 LB/Hr HHP steam letdown resulted in a ST power output loss of about 2 MWe for Case 3 because of its lower sulfur feed.

Table 4.11
Overall Intermediate Pressure (Nominal 300 psig 500 °F) Steam Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
IP Steam, 300PSIG, 500F:				
ASU	0	15	0	15
Letdown from HHP Stm	0	0	12	0
Letdown from HP Stm	21	0	0	0
Letdown to LP Stm	0	5	0	0
Letdown Desuperheat	0	1	3	0
TOTAL IP STEAM, LB/Hr	21	21	15	15

As shown in Table 4.12, the AGR/SRU/TGTU system in Case 1 consumes twice as much LP steam as Case 3 because its coal sulfur content is twice that of Case 3 coal. Coupled with the lower LP steam generation, Case 3 consumes (131 - 23) - (70 - 12) = 50,000 LB/Hr less LP steam than Case 1. This 50,000 LB/Hr reduction in LP steam consumption represents roughly 4% increase in the Case 3 STG LP steam flow which results in a power output gain of about 4 MWe, or 0.3 percentage point gain in overall plant efficiency for Case 3 because of lower sulfur feed.

Also as shown in Table 4.12, Case 3 SWS consumes over four times the LP steam as Case 1 because the Case 3 chloride purge is 4-to-5 times the Case 1 chloride purge. The net result is that Case 3 extracts 125,000 LB/Hr more LP steam from the STG than Case 1. This is roughly 10% of the total STG LP steam flow which results in a power output loss of about 11 MWe from the STG, or 0.7 percentage point drop in overall plant efficiency for Case 3 because of higher chloride feed.

Table 4.12
Overall Low Pressure (Nominal 60 psig 500 °F) Steam Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
LP Steam, 60PSIG, 551F:				
HRSG	59	0	45	0
AGR/SRU/TGTU Generation	23	0	12	0
AGR/SRU/TGTU Consumption	0	131	0	70
SWS Consumption	0	40	0	166
Letdown from IP Stm	5	0	0	0
STG Extraction Steam	87	0	182	0
STG Extraction Desuperheat	0	0	0	0
BOP (Deaerator Makeup)	0	4	0	3
TOTAL LP STEAM, LB/Hr	175	175	239	239

4.8 OVERALL PROCESS WATER BALANCE

Table 4.13 shows the overall process water breakdown and balance for the two nominal 600 MWe reference IGCC plants. The process water balance only accounts for water that enters into or exits from process streams, including reaction formed or consumed water. The process water balance does not include water that does not directly mix with process streams such as steam, condensate, and cooling water to and from heat exchangers. The overall plant water balance which includes both process and non-process related water is shown in Table 4.14.

The main process water usage is to meet coal slurry preparation and gasifier makeup needs. The major discharges are the water contained in the slag and ash solid wastes, and with the gasifier purge. It is routed to the SWS to remove H_2S, followed by sending it to the WWT plant for further treatment before being disposed back to the river. The LTGC condensate will be routed as part of the gasifier makeup water

Table 4.13
Reference IGCC Plant Overall Process Water Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVERALL PROC H2O BAL, LB/HR:	IN	OUT	IN	OUT
AR Coal Feed	38,273	0	50,664	0
Slurry Water	216,856	0	183,106	0
Vac Flash Gas to SRU	0	4	0	4
O2 to Gasifier	0	0	0	0
Slag/Ash to Disposal	0	79,732	0	51,489
Gasifier Rx H2O	0	97,758	0	89,514
Gasifier MU H2O	526,431	0	1,161,284	0
Gasifier Purge H2O	0	141,241	0	870,109
COS Hydroly Rx H2O	0	458	0	245
LTGC Condensate	0	461,324	0	382,632
RTI Fluidization N2	0	0	0	0
AGR Strip N2	0	0	0	0
AGR MUW	3,054	0	1,625	0
Treated Syngas from AGR	0	948	0	987
Acid Gas to SRU	0	1,718	0	915
AGR H2O Purge	0	1,436	0	788
Acid Gas fr AGR	1,718	0	915	0
Vac Flash Gas to SRU	4	0	4	0
Fuel Gas to TGTU	15	0	8	0
Comb Air to SRU/TGTU	644	0	345	0
Sulfur Product	0	0	0	0
TGTU Incin Exhaust	0	17,086	0	9,183
TGTU Sour Condensate	0	1,617	0	837
SRU/TGTU Comb & Rx H2O	16,322	0	8,748	0
FT Tail Gas to GTCC	932	0	979	0
Suppl't NG to GTCC	0	0	0	0
Comb Air to GTCC	44,379	0	44,379	0
NOx Steam to GTCC	0	0	0	0
GTCC HRSG Exhaust	0	294,204	0	309,133
GT Combustion Rx Water	248,892	0	263,775	0
TOTAL PROCESS WATER, LB/Hr	1,097,521	1,097,525	1,715,832	1,715,835

4.9 REFERENCE IGCC OVERALL WATER BALANCE

The Reference IGCC plant imports approximately 4200 gpm of raw river water for Case 1 and 5600 gpm for Case 3 to makeup for BFW/Process/Plant/Potable Water and Cooling Tower consumption. Table 5.7-1 presents the estimated overall water balance for the two Reference IGCC plants.

The difference in raw water demands between the two cases is due mainly to the gasifier chloride purge differences. Beside makeup for gasifier chloride purge, 75% of the remaining raw water import is used for cooling tower makeup.

Approximately 1300 gpm for Case 1 and 2800 gpm for Case 3 of treated effluent is discharged back to the river. Again, the effluent difference between Case 1 and Case 3 is due to the gasifier chloride purge difference. Besides the gasifier chloride purge, the remaining effluent is made up of approximately 50% cooling tower blowdown, 25% of raw water treating purge, and 25% of other miscellaneous purges.

Table 4.14
Reference IGCC Plant Overall Plant Water Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVERALL PLT H2O BAL, LB/HR:	IN	OUT	IN	OUT
Water in AR Coal Feed	38,273	0	50,664	0
Vac Flash Gas to SRU	0	4	0	4
Slag/Ash to Disposal	0	79,732	0	51,489
Gasifier Purge to SWS/WWT	0	141,241	0	870,109
Gasifier Rx H2O	0	97,758	0	89,514
COS Hydroly Rx H2O	0	458	0	245
AGR MUW	0	3,054	0	1,625
AGR H2O Purge to SWS	0	0	0	0
Water in Treated Syngas	0	948	0	987
Water in Acid Gas to SRU	0	1,718	0	915
TGTU Sour Cond to SWS	0	0	0	0
Proc Stm Cond Purge to WWT	0	12,452	0	15,668
Steam Syst Cond Purge to WWT	0	67,290	0	65,163
Boiler Blowdowns to WWT	0	14,896	0	14,751
Deaerator Vent	0	200	0	200
CT Evaporatn & Drift Losses	0	1,315,035	0	1,329,477
CT Blowdowns	0	266,547	0	251,584
Potable Water to Sewer	0	2,083	0	2,083
Plant Water to Sewer	0	20,000	0	20,000
Raw Water Treat Purge to WWT	0	128,357	0	159,850
Raw H2O Import by difference	2,113,500	0	2,823,000	0
Total Plant Water, LB/Hr	2,151,773	2,151,773	2,873,664	2,873,664
GPM Raw H2O Import	4,227		5,646	

The above overall water balance assumed the following:

- 5 cycles of cooling tower concentration
- 70% cooling tower heat regeneration via evaporation
- 20°F cooling water temperature rise
- Drift losses at 0.001% of circulation rate
- Approximately 85% RO/ Demin recovery
- 5% condensate purge
- 95% raw water treating recovery
- No recycle or re-claim treated waste water to minimizing water usage.

4.10 REFERENCE IGCC POWER BALANCE

The 600 MWe Reference IGCC plant has a net power export of 558 MWe when burning the 2004 NETL coal, and 585 MWe with the 2006 NETL coal feed. Table 4.15 shows the breakdown of the overall power balance for the two Reference IGCC plants. The GT power output is representative of 60 ^{o}F ambient temperature operation, at the project site elevation.

GT output is 5.8% higher for Case 3 as compared to Case1. The bulk of this GT output increase is the direct result of its higher total fuel gas LHV (about 5.5%; see Section 4.11 Reference IGCC Overall Fuel Gas Balance). The smaller additional increase of 5.8 – 5.5 = 0.3% GT output is due to increase in Case 3 fuel gas mass flow.

STG-to-GT output is lower for Case 3 when compared to Case 1. The expected Case 3 ST output if strictly pro-rated from Case 1 is (260.8 / 430.7) x 455.7 = 276 MWe, or 13 MWe higher than what is shown in Table 4.15. Bulk of this reduction (approximately 11 MWe) in STG output for Case 3 is due to its higher coal chloride content, which increases the SWS (sour water stripping) reboiling steam consumption needed to handle the chloride purge. The remaining 2 MWe drop in steam turbine output is due to Case 3's lower HP and IP steam generation associated with its lower sulfur coal feed.

Table 4.15
Reference IGCC Plant Overall Power Balance

	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
GENERATION, MWe:		
Gas Turb Generator System	430.7	455.7
Steam Turb Generator System	260.8	263.2
Total Gross Output	691.5	719.0
CONSUMPTION, MWe:		
Coal Handling/Storage	5.6	5.1
Gasification/Feed Prep	4.4	2.8
Air Separation	38.4	39.2
O2 Compression	22.6	23.1
Shift & LT Gas Cooling	0.9	0.7
Acid Gas Removal & SWS	3.0	2.0
Sulfur Recovery	1.0	0.5
RTI Warm Gas Clean Up/DSRP	---	---
CO2 Dehydr'n & Comp	0.0	0.0
Plt Air/Instru Air/N2 System	30.4	31.7
HRSG/Boiler Plt/BFW/DM/Cond	7.3	8.2
CW Pumps & CT Fans	8.2	8.2
Flue Gas CO2 Recovery	---	---
BOP	11.5	12.5
Total Consumption	133.2	134.0
Net Export	558.3	585.0

4.11 REFERENCE IGCC OVERALL FUEL GAS BALANCE

Table 4.16 lists the estimated overall fuel gas balance for the two Reference IGCC plant. Pilot natural gas consumption (approximately 1 to 3% of net process gas fired LHV) is not included in the balance. The balance also does not include offsite sour flare header/stack syngas or natural gas purge consumptions.

While the same volume of syngas is produced in the 1800 ft^3 GE gasifiers (constant residence time), raw syngas LHV is about 2.5% higher for Case 3. This difference reflects the impact of burning more moisture-ash-free (MAF) coal to vaporize more water in the slurry feed for Case 1, as shown by its higher water-to-MAF coal ratio.

Treated syngas LHV available to the gas turbines is 5.5% higher for Case 3 after acid gas removal and deducting TGTU fuel demands. This increase in available LHV reflects the impact of higher sulfur coal for Case 1.

Table 4.16
Reference IGCC Plant Overall Fuel Gas Balance

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
OVERALL FUEL GAS BAL, MMBtu(LHV)/Hr:	Production	Consumptions	Production	Consumptions
Raw Syngas from Radiant Cooler	3,701	0	3,795	0
Import Natural Gas	0	0	0	0
Syngas in Quench Water	0	1	0	1
COS Hydrolysis Reaction Loss	0	< 0.3	0	< 0.3
Acid Gas to SRU	0	155	0	83
Treated Syngas to TGTU Rx & Incinerator	0	57	0	31
Treated Syngas to GT	0	3,488	0	3,680
TOTAL Fuel Gas LHV, MMBtu/Hr	3,701	3,701	3,795	3,795
Syngas Flow Exit Gasifiers, Actual Ft^3/sec	743		741	

4.12 PLANT COOLING WATER AND AIR COOLER LOADS

Table 4.17 summarizes the Reference IGCC plant cooling water (CW) and air cooler (AC) cooling loads for Case 1 and Case 3. Roughly 65% of the total CW load is attributable to the STG surface condenser. The large Case 3 SWS air cooler load reflects processing the large chloride purge from the gasification system.

Split between CW and AC is based on air cooling to 140 ^oF before switching to water cooling.

Table 4.17
Reference IGCC Plant Cooling Loads

	CASE 1 2004 NETL Illinois #6	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
PLANT COOLING LOADS, MMBtu/Hr:	CW	Air Cool	CW	Air Cool
ASU/O2 Comp	342		344	
Gasification (Ash & Purge H2O Cool)	81		185	
COS Hydrolysis & LTGC	33	392	29	295
AGR	114	0	61	0
SRU/TGTU	26		14	
SWS		49		206
STG Surface Cond	1,266		1,226	
Offplot CW Demands	6		6	
Total CW Cool Load, MMBtu/Hr	1,868	441	1,864	501

4.13 ESTIMATED CATALYST AND CHEMICALS CONSUMPTION

Table 4.18 lists the estimated overall catalyst and chemical (C&C) consumption breakdown for the 600 MWe Reference IGCC plants. Estimated total annual catalyst and chemicals (C&C) cost is approximately $6 MM or approximately 0.6% of the total installed cost. Case 3 has slightly lower C&C cost for gasification and sulfur blocks, and slightly higher C&C cost for GTCC and BOP blocks. Lower gasification C&C cost for Case 3 is due to reduced chemical consumption because of its lower coal ash content. Lower sulfur block C&C cost for Case 3 is due to the reduced Claus and SCOT catalysts consumption because of its lower coal sulfur content. Higher GTCC and BOP C&C costs for Case 3 are due to the large increase in raw water and waste water treatment chemical demands associated with its large chloride purge requirement. A $1MM/year contingency allowance is included to cover costs for chemicals excluded because they are either undefined or are coal specific (such as slurry feed viscosity and pH control additives) which need to be defined by licensors later.

Table 4.18
Reference IGCC Plant Overall Catalyst and Chemical Consumption

	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
ANNUAL CATALYSTS & CHEM COSTS:	$MM/Yr	$MM/Yr
Gasification Block	0.6	0.5
AGR/SRU/TGTU Block	0.9	0.7
Power & BOP Block	3.4	3.8
Contingency Allowance	1.1	1.0
Total C&C Cost, $MM/Year	6.0	6.0

4.14 ESTIMATED CAPITAL COST AND BASIS

Table 4.19 is the estimated installed cost of the Case 1 and Case 3 Reference IGCC plant, listed by individual units. Costs shown are capacity factored estimates based on Nexant's in-house data with an accuracy of +/- 30%. The estimated costs are for December, 2006.

Each unit installed cost shown includes material, labor and field indirects. Material costs include major equipment, bulk material and S/C (subcontractor) costs. A 6% sales tax and a 4% shipping cost allowance are included to adjust for midwest US location.

Labor cost assumes construction by union labor at an average hourly labor wage (including fringe benefits, payroll-based taxes and insurance premiums) of $39.00, and a labor productivity of 1.46 (times standard California MH) for the midwest US location.

Field indirect costs include setup, maintenance and removal of temporary facilities, construction equipment, tools, consumables, purchased utilities, field office costs including the payroll cost of supervisory and administrative personnel, and support services such as surveying, security, warehousing, maintenance of tools and equipment, etc. Field indirect costs are included at 100% of the direct labor costs based on in-house historical data.

Home office cost includes service charges for engineering, procurement services, and construction management. Home office cost is factored at 10% of TIC based on historical data for plants of this size. No special allowances were provided for new technology.

Startup and training costs, license/royalty fees, contingencies and owners costs are not included.

In addition, the following are assumed:

- Black-start power generation facility is not included. It is assumed that black-start and emergency shutdown power supply will be available from the power grid.
- No contaminated soil/hazardous waste to be removed.
- No piling, site blasting and ripping are needed.
- Royalties and licensing fees are not included.
- Vendor representative fees for startup assistance are not included.

Table 4.19
2006 Reference IGCC Plant Capital Cost, $1,000,000

	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
CAPITAL COSTS, 2006 $MM		
Coal Handling/Storage	18.4	17.8
Gasification/Feed Prep	159.0	151.5
Spare Gasifiers	79.5	75.8
Air Separation	79.4	80.5
O2 Compression	Incl in ASU	Incl in ASU
COS Hydroly, Shift & LTGC	36.8	37.2
Acid Gas Removal & SWS	131.8	147.9
Sulfur Recovery	25.4	16.4
Tail Gas Treating Unit	32.3	20.8
RTI Warm Gas Clean Up/DSRP	---	---
CO2 Dehydr'n & Comp	---	---
Plt Air/Instru Air/N2 System	23.1	23.8
Gas Turb Generator System	140.7	146.4
HRSG/Boiler Plt/BFW/DM/Cond	48.2	49.0
Steam Turb Generator System	48.9	49.2
CW Pumps & CT Fans	17.2	16.5
Flue Gas CO2 Recovery	---	---
BOP	164.6	179.9
Total Installed Cost	1,005.2	1,012.6
Home Office Cost	100.5	101.3
Contingency	0.0	0.0
Total Plant Cost	1,105.8	1,113.8

4.15 ESTIMATED OPERATING COST AND ASSUMPTIONS

Table 4.20 presents the itemized annual operating cost (incomes and expenses) for the Case 1 and Case 3 Reference IGCC plants. The operating cost is based on an annual overall on-stream factor (equivalent availability) of 85%.

Table 4.20
Reference IGCC Plant Annual Operating Costs, $1,000,000/Year

	CASE 1 2004 NETL Illinois #6	CASE 3 2006 NETL Illinois #6
INCOMES & EXPENSES:	$MM/Yr	$MM/Yr
AR Coal Cost	78.7	79.2
Raw Water Import	0.7	0.9
Cat & Chem Consumptn	6.0	6.0
Royalties	0.0	0.0
Mainten Labor & Mat	33.2	33.4
Admin & Labor Salary	14.4	14.4
Overheads & Benefits	5.0	5.0
Insurances	11.1	11.0
Local Taxes	11.1	11.0
Sulfur Sale	(5.5)	(3.0)
Ash & Slag Disposal	2.7	1.7
Waste Water Disposal	0.0	0.0
CO2 Sequestn Credit	0.0	0.0
CO2 Emission Penalty	0.0	0.0
Bank Loan Repayment	97.3	98.0
Investment Recovery	53.6	53.9
Total Annual Expenditure	308.1	311.9
Annual Power Export, MW-Hr	4,154,868	4,355,910
Cost of Electricity, ¢/kW-Hr	7.42	7.16

The above annual operating costs assume the following variable costs:

Illinois #6 Coal Cost	$2.00 / MMBtu (HHV AR)
Raw Water Cost	$0.35 / 1000 Gallon
Ash and Slag Disposal Cost	$10 / Short Ton
Catalysts and Chemical Cost	0.6 % TIC
Maintenance Labor and Material Cost	3.0 % TPC
Sulfur Sale Revenue	$70 / Short Ton

In addition to the above operating costs, the following assumed fixed costs are included:

Admin and Operating Avg Salaries	$60,000 / Year / Employee 240 Employees
Overheads and Benefits	35 % Avg Annual Salaries

Insurance	1.0 % TPC
Local Property Tax	1.0 % TPC
Bank Loan Interest	7.5 % / Year
Investment ROI	15 % / Year
Owner's Investment	20 % TPC

Bank loan repayment and owner investment recovery are amortized annual repayments on the initial bank loans and owner investments over the 30 years assumed life of the plant at the specified annual interest rate. These annual repayments are equivalent to the depreciation charges on capital investment plus the interest expenses. Initial total plant capital costs and funding are list below:

	Case 1	Case 3
Capital Cost, $MM:		
Total Installed Cost (TIC)	1,005.2	1,012.6
Home Office Cost, 10% of TIC	100.5	101.3
Contingency, 0% of TIC	0.0	0.0
Total Plant Cost (TPC)	1,105.8	1,113.8
Initial Operating Capital	50.4	50.5
Cost of Land	0.0	0.0
Total Initial Cost	1,156.2	1,164.3
Funding, $MM:		
Owner's Investment (20%)	231.2	232.9
Bank Loans	925.0	931.4
Total Initial Investment	1,156.2	1,164.3

Royalty costs are excluded. Waste water disposal cost is excluded since waste water treating facilities are provided to ensure effluents meet all federal and state discharge specifications. Also, federal and state income tax charges are not included.

Cost of land is excluded. It is assumed that land will appreciate at the same rate as the loan interest and the return on investment so that land cost (including accumulated interests) will be salvaged at end of the plant life.

The use of a conventional syngas desulfurization process such as Selexol requires cooling the raw syngas leaving the gasifier to a much lower temperature. For an IGCC process, the low temperature cleaned syngas then would have to be re-heated before being sent to the combustion turbine. This cooling and reheating cycle introduces an efficiency penalty to an IGCC plant. With a high temperature syngas desulfurization process such as RTI's WGCU, syngas can be cleaned at an elevated temperature and sent to the combustion turbine without the need for re-heat; thus it offers potential improvement in overall thermal efficiency.

This section provides an overview of the RTI WGCU IGCC conceptual design for Case 2 using coal #1 (2004 NETL design coal) and Case 4 using coal #2 (2006 NETL design coal). Except for throughputs, the same design concept is applicable to both Illinois No. 6 coal feeds.

The WGCU IGCC conceptual design is developed with the same features as those for the Reference IGCC design as described in Section 4, except for the following:

- No syngas scrubbing/quench cooling,
- No COS hydrolysis,
- Replace the conventional Selexol AGR/Claus SRU/SCOT TGTU technology with RTI's WGCU/DSRP high temperature sulfur removal and recovery technology,
- Replace the Reference IGCC low-temperature (LT) mercury (Hg) removal technology with RTI's proprietary high-temperature (HT) Hg removal technology,
- Add high-temperature (HT) dry HCl removal using Na_2CO_3 adsorption,
- Include cost allowance for adding SCR to reduce HRSG NOx emission due to high syngas NH3 content, and
- Include a convective syngas cooler upstream of WGCU for waste heat recovery.

5.1 OVERALL BLOCK FLOW DIAGRAM AND MAJOR STREAM FLOWS

Figure 5.1 shows the overall process block flows for the conceptual WGCU based IGCC. BOP units are not included in the BFD except for the Combined Cycle Systems. Major stream flows and properties are shown on Table 5.1 for the 2004 NETL coal feed (Case 2), and Table 5.2 for the 2006 NETL coal feed (Case 4) operations.

Figure 5.1
WGCU IGCC Overall Process Block Flow Diagram

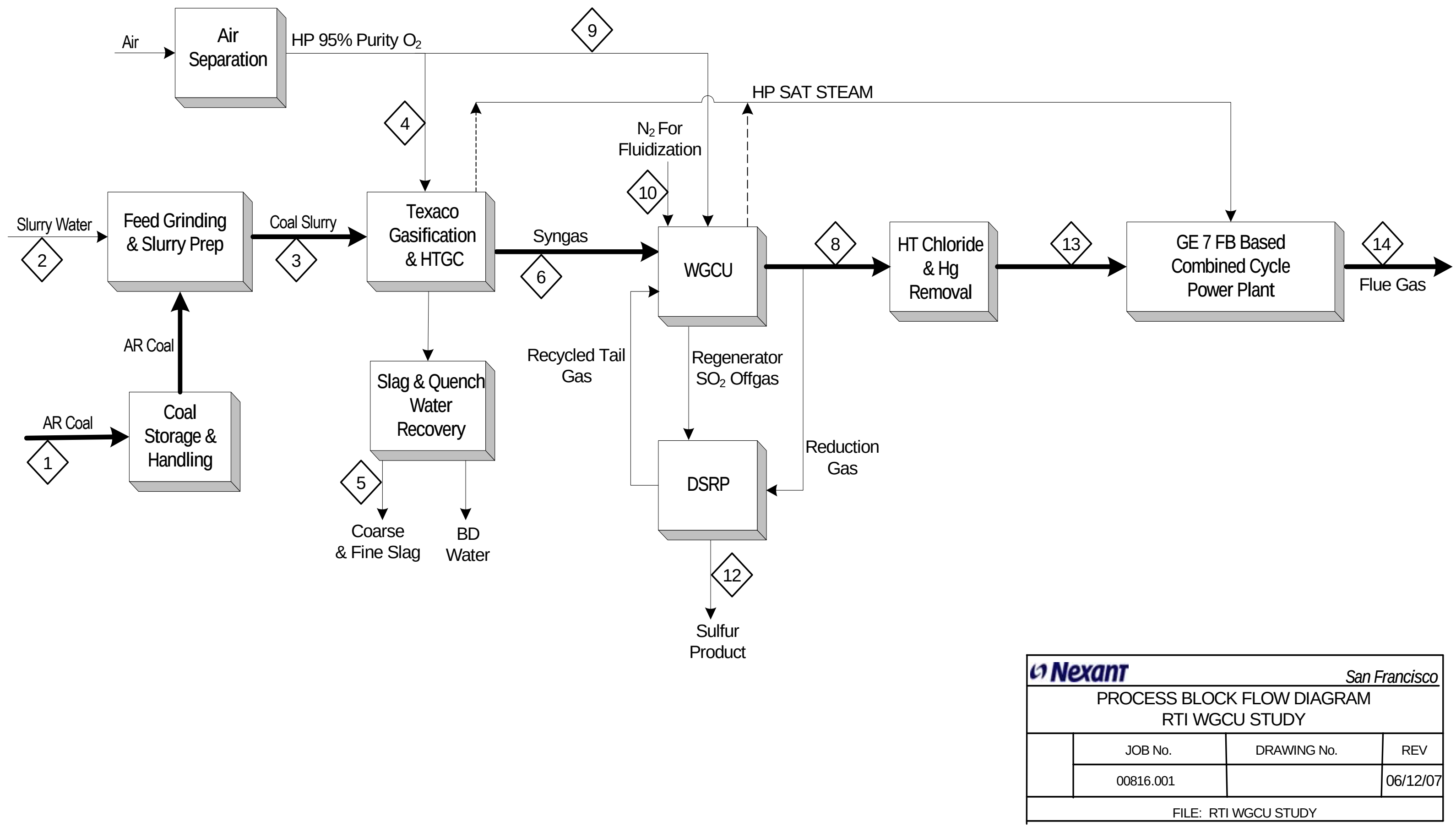


Table 5.1

WGCU IGCC - Major Stream Flows and Properties for 2004 NETL Illinois #6 Coal

Stream Number			1.	2.	3.	4.	5.	6.	9.	10.	12.	13.	14.
Stream Description			AR Coal Feed	Make-Up H2O to Slurry Prep	Coal Slurry to Gasifiers	95.00% Oxygen to Texaco Gasific'n	Fines & Slag (Dry Basis)	Cooled Syngas from Radiant Boiler	95.00% Oxygen to RTI WGCU	Fluid N2 to RTI WGCU	Molten Sulfur from DSRP	Total HP Fuel Gas To Gas Turbine	HRSG Flue Gas Vent to Stack
Pressure, psia			14.7	14.7	664.7	664.7	14.7	524.7	664.7	664.7	14.7	414.7	14.8
Temperature, deg F			60.0	60.0	250	140.0	180.0	830.0	140.0	100	---	550.0	261.0
Flow Rate: MMSCFD Vapor			---	---	---	108.1	---	437.2	10.17	45.79	---	483.5	2524.4
: STPD Liquid			459	2,602	3,062	---	---	---	---	---	---	---	---
: STPD Solid			5,303	---	5,303	---	870	---	---	---	256.0	---	---
Mass Flow Rate, lb/hr			480,219	216,856	697,075	381,352	72,473	1,005,721	35,854	140,840	21,337	1,160,058	8,053,824
Molecular Weight			---	18.02	---	32.12	---	20.95	32.12	28.013	32.06	21.85	29.06
HHV, Btu/SCF (Btu/LB)			(10,999)	---	(7,577)	0.0	---	---	0.00	0.00	(4,863)	190.5	4.7
LHV, Btu/SCF (Btu/LB)			(10,558)	---	(7,274)	0.0	---	---	0.00	0.00	(4,863)	168.4	0.0
Total MMBtu(LHV)/Hr			5,070	0	5,070						104	3,392	0
Vapor Composition, Mole %:													
	N2	28.013	---	---	---	2.3%	---	1.0%	2.3%	100.0%	0.0%	10.4%	68.8%
	O2	31.999	---	---	---	95.0%	---	0.0%	95.0%	---	0.0%	0.0%	12.3%
	CO2	44.010	---	---	---	0.0%	---	13.6%	---	---	0.0%	13.8%	8.6%
	Ar	39.948	---	---	---	2.7%	---	0.7%	2.7%	---	0.0%	0.6%	0.9%
	H2	2.016	---	---	---	0.0%	---	29.2%	---	---	0.0%	25.2%	0.0%
	CO	28.010	---	---	---	0.0%	---	35.9%	---	---	0.0%	31.0%	0.0%
	H2S	34.076	---	---	---	0.0%	---	1.3%	---	---	0.0%	0.0%	0.0%
	COS	60.070	---	---	---	0.0%	---	0.1%	---	---	0.0%	0.0%	0.0%
	CH4	16.043	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	C2H6+	30.070	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	SO2	64.059	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	Steam	18.016	---	---	---	0.0%	---	18.2%	---	---	0.0%	18.9%	9.3%
Total %			0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%

Table 5.2

WGCU IGCC - Major Stream Flows and Properties for 2006 NETL Illinois #6 Coal

Stream Number			1.	2.	3.	4.	5.	6.	9.	10.	12.	13.	14.
Stream Description			AR Coal Feed	Make-Up H2O to Slurry Prep	Coal Slurry to Gasifiers	95.00% Oxygen to Texaco Gasific'n	Fines & Slag (Dry Basis)	Cooled Syngas from Radiant Boiler	95.00% Oxygen to RTI WGCU	Fluid N2 to RTI WGCU	Molten Sulfur from DSRP	Total HP Fuel Gas to Gas Turbine	HRSG Flue Gas Vent to Stack
Pressure, psia			14.7	14.7	664.7	664.7	14.7	524.7	664.7	664.7	14.7	414.7	14.8
Temperature, deg F			60.0	60.0	250	140.0	180.0	840.0	140.0	100	---	550.0	261.3
Flow Rate: MMSCFD Vapor			---	---	---	110.2	---	436.0	5.44	24.49	---	460.7	2546.8
: STPD Liquid			608	2,197	2,805	---	---	---	---	---	---	---	---
: STPD Solid			4,859	---	4,859	---	562	---	---	---	136.9	---	---
Mass Flow Rate, lb/hr			455,608	183,106	638,714	388,725	46,801	979,260	19,174	75,319	11,411	1,061,797	8,124,256
Molecular Weight			---	18.02	---	32.12	---	20.46	32.12	28.013	32.06	20.99	29.05
HHV, Btu/SCF (Btu/LB)			(11,666)	---	(8,322)	0.0	---	---	0.00	0.00	(4,863)	212.0	4.6
LHV, Btu/SCF (Btu/LB)			(11,138)	---	(7,945)	0.0	---	---	0.00	0.00	(4,863)	189.1	0.0
Total MMBtu(LHV)/Hr			5,075	0	5,075						55	3,630	0
Vapor Composition, Mole %:													
	N2	28.013	---	---	---	2.3%	---	1.0%	2.3%	100.0%	0.0%	6.3%	69.5%
	O2	31.999	---	---	---	95.0%	---	0.0%	95.0%	---	0.0%	0.0%	11.9%
	CO2	44.010	---	---	---	0.0%	---	12.5%	---	---	0.0%	12.7%	8.6%
	Ar	39.948	---	---	---	2.7%	---	0.7%	2.7%	---	0.0%	0.6%	0.9%
	H2	2.016	---	---	---	0.0%	---	30.8%	---	---	0.0%	28.5%	0.0%
	CO	28.010	---	---	---	0.0%	---	37.5%	---	---	0.0%	34.7%	0.0%
	H2S	34.076	---	---	---	0.0%	---	0.7%	---	---	0.0%	0.0%	0.0%
	COS	60.070	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	CH4	16.043	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	C2H6+	30.070	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	SO2	64.059	---	---	---	0.0%	---	0.0%	---	---	0.0%	0.0%	0.0%
	Steam	18.016	---	---	---	0.0%	---	16.7%	---	---	0.0%	17.2%	9.1%
Total %			0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%

5.2 RTI WGCU PROCESS DESCRIPTION

RTI's WGCU process consists of two major system components: High Temperature Desulfurization process (HTDS) and Direct Sulfur Recovery process (DSRP). Additional companion processes are included to remove mercury, ammonia, chloride and carbon dioxide, etc., as needed, to meet environmental emission requirements.

Figure 5.2 shows a simplified WGCU process scheme, located at the downstream of the gasifier radiant cooler. The HTDS process is consisted of a pair of fluidized bed reactors. In the HTDS process, the hot raw syngas from the GE gasifier radiant boiler is first cooled to the operating temperature of the RTI WGCU absorber at approximately 800 ^oF, via a fire tube convection boiler. In the process, a high-pressure 1700 psig saturated steam is generated and is sent directly to the HRSG system. The raw syngas, mixed with a tail gas recycled stream, is then sent to a cyclone for bulk ash and char removal. The captured solids, still containing un-reacted carbon, are recycled to the gasifier. The syngas leaving the cyclone is routed to the WGCU absorber where it is contacted with the circulating sorbent to remove H_2S and COS. The RTI WGCU process is based on a ZnO sorbent, where the following reactions are believed to take place in the absorber where it comes into contact with the raw syngas:

$$H_2S + ZnO = ZnS + H_2O$$

$$COS + ZnO = ZnS + CO_2$$

The regenerated sorbent from the regenerator, along with the recycled sorbent from the absorber standpipe (Figure 5.3) enter the absorber near the bottom of the unit. Most of the sulfur absorption takes place in the absorber. The mixture leaves the top of the absorber into a cyclone where the solid sorbent containing ZnS is separated from the sulfur free syngas. Part of the solids is recycled to the absorber via a standpipe. A diverter valve located in the absorber standpipe takes a slip stream of these solids and feeds it to the regenerator.

Within the regenerator, the ZnS containing sorbent comes into contact with a mixture of oxygen and nitrogen at a pre-determined ratio. The oxygen then reacts with the ZnS and forms SO_2 according to the following reactions:

$$ZnS + 1.5\ O_2 = ZnO + SO_2$$

The above reaction is exothermic, raising the temperature of the resulting mixture. A cyclone is used to separate the solids and recycled it to the absorber. The regenerator offgas containing SO_2 is heat exchanged with the incoming oxygen/nitrogen mixture before sending onto a companion DSRP (Direct Sulfur Recovery Process) unit for sulfur removal.

SO_2 and N_2 from HTDS regeneration, after heat exchanged cooling and filtration to remove entrained solids, are sent onto the fixed bed catalytic DSRP reactor where SO_2 is reduced to elemental sulfur according to the following reactions:

$$SO_2 + 2\ CO = 2\ CO_2 + S \quad \text{and}$$

$$SO_2 + 2\ H_2 = 2\ H_2O + S$$

CO and H_2 are provided by a slip stream from the HTDS absorber. The SO_2 is converted to elemental sulfur in the DSRP reactor. The reaction is exothermic and it raises the reaction outlet mixture temperature. The product stream from the DSRP reactor is sent onto a two stage sulfur condenser unit where the elemental sulfur is condensed and separated. Heat is recovered by making low pressure steam.

The tail gas containing CO_2, N_2 and steam is directed to 2nd stage DSRP (Hydrogenation) reactor where the residual SO_2 is hydrogenated to H_2S in according with the following reduction reaction:

$$SO_2 + 3\ H_2 = H_2S + 2\ H_2O$$

The hydrogenated stream is then cooled in two stages. In the first stage, the gas is cooled by generating low pressure steam. In the second stage the gas is further cooled to 315 ^oF by heat exchange with boiler feed water (BFW). The cooled stream is then compressed and recycled as feed to the HTDS reactor.

Companion processes are included in the overall WGCU design, to remove mercury, chloride and ammonia to meet environmental emissions requirement, as follows:

- A high temperature duel candle filter system to remove entrained solids from the desulfurized syngas stream leaving the WGCU process before sending the stream onto the fixed-bed mercury removal vessel,

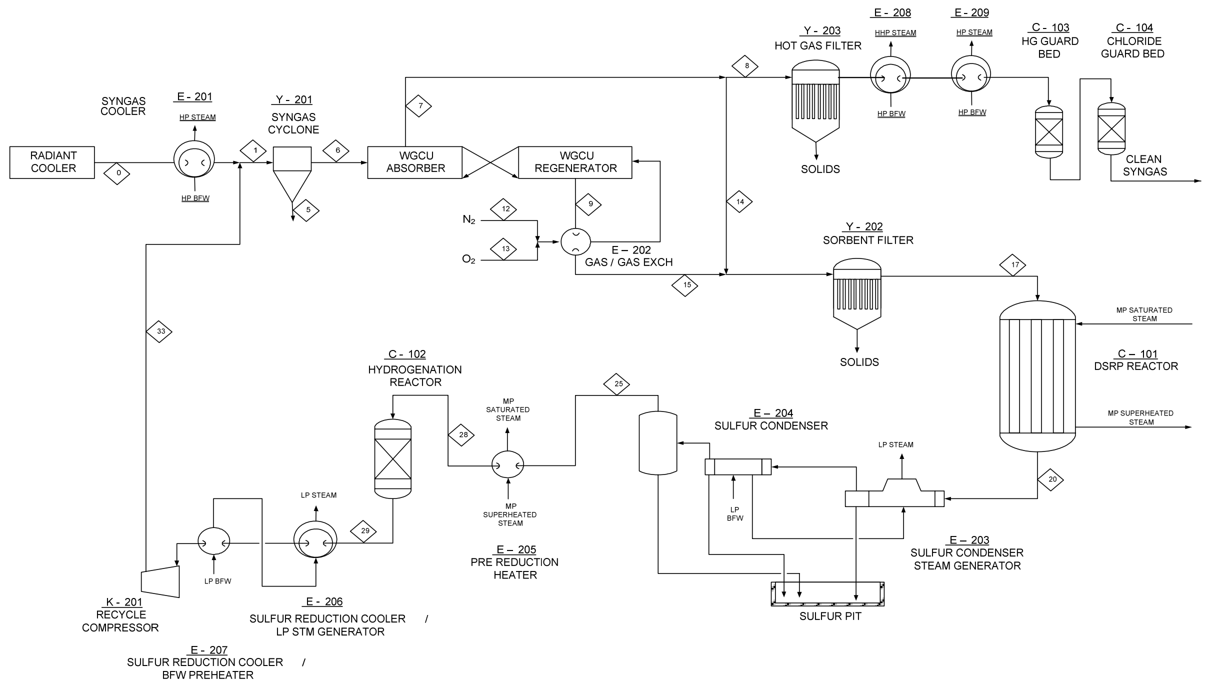
- High temperature (~ 550 ^oF) fixed-bed RTI proprietary mercury removal process,

- A companion high temperature (~ 550 ^oF) fixed-bed chloride guard bed for HCl removal, based on reaction with sodium bicarbonate in according with the following reaction –

$$HCl + NaHCO_3 = NaCl + CO_2 + H_2O$$

- Inclusion of an SCR (Selective Catalytic Reduction) onto the power train for NOx emissions control; thus no online ammonia removal is provided with the WGCU design.

Figure 5.2 Simplified Overall WGCU Process Scheme



5.3 WGCU IGCC PLANT OVERALL PERFORMANCE SUMMARY

Table 5.3 shows a summary of the estimated plant performance for Case 2 and Case 4 WGCU IGCC design, feeding 2004 NETL and 2006 NETL Illinois No. 6 coals, respectively. Coal feed processed is based on a constant gasifier residence time of 5 seconds at 550 psig and 2450 ^{o}F exit conditions. Because of the dry chloride removal process, there is essentially no difference in waste water production between Case 2 & Case 4 even though Case 4's coal feed contains five times more chloride.

Table 5.3
WGCU IGCC Plant Overall Imports and Exports
(Excluding Chemicals and Catalysts)

	CASE 2 WGCU IGCC 2004 NETL Coal	CASE 4 WGCU IGCC 2006 NETL Coal
CONSUMABLES:		
AR Coal Feed,STPD	5,763	5,467
Raw Water, GPM	4,422	4,288
95.0% O2, STPD	5,006	4,895
99% N2, STPD	2,919	3,959
NG Import, MMBtuLHV/Hr	0	0
PRODUCTS:		
Power Export, MWe	589	641
Sulfur, STPD	256	137
Slag & Ash, STPD Dry	870	562
Waste Water, GPM	1,084	1,085
Recovered CO2, STPD	0	0
OVERALL ELECTRIC EFFICIENCIES:		
Gross Heating Value Basis	38.1 % HHV	41.2 % HHV
Net Heating Value Basis	39.7 % LHV	43.1 % LHV

5.4 WGCU IGCC PLANT OVERALL MATERIAL BALANCE

Table 5.4 shows the overall process mass balance for the two WGCU IGCC designs.

Table 5.4
WGCU IGCC Plant Overall Process Mass Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVERALL PROCESS MASS BAL, LB/HR:	IN	OUT	IN	OUT
AR Coal Feed	480,219	0	455,608	0
Slurry Water	216,856	0	183,106	0
Vac Flash Gas to SRU	0	0	0	0
O2 to Gasifier	381,352	0	388,725	0
Slag/Ash to Disposal	0	152,206	0	98,290
Gasifier MU H2O	79,732	0	51,489	0
Gasifier Purge H2O	0	0	0	0
HCL Removed	0	247	0	1,546
LTGC Condensate	0	(0)	0	0
RTI Fluidization N2	176,335	0	94,302	0
AGR Strip N2	0	0	0	0
AGR MUW	0	0	0	0
Treated Syngas from AGR	0	1,160,058	0	1,061,797
AGR H2O Purge	0	0	0	0
Fuel Gas to TGTU	0	0	0	0
Comb Air to SRU/TGTU	0	0	0	0
Sulfur Product	0	21,337	0	11,411
TGTU Incin Exhaust	0	0	0	0
TGTU Sour Condensate	0	0	0	0
Treated Syngas to GTCC	1,160,058	0	1,061,797	0
Suppl't NG to GTCC	0	0	0	0
Comb Air to GTCC	6,826,846	0	6,826,846	0
NOx N2 to GTCC	66,911	0	235,603	0
GTCC HRSG Exhaust	0	8,053,824	0	8,124,256
Total Process Mass Balance, LB/Hr	9,388,308	9,387,671	9,297,475	9,297,300

5.5 WGCU IGCC PLANT OVERALL CARBON BALANCE

Table 5.5 shows the overall carbon balance of the two WGCU IGCC Plants.

Table 5.5
WGCU IGCC Plant Overall Carbon Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVERALL CARBON BAL, LB/HR:	IN	OUT	IN	OUT
COAL FEED	290,137	0	290,426	0
CARBON IN SLAG	0	2,318	0	1,497
CARBON IN ASH	0	1,742	0	1,125
AIR TO GT AIR COMP	844	0	844	0
ACID GAS TO SRU	0	0	0	0
HRSG VENT	0	286,920	0	288,648
TOTAL CARBON, LB/HR	290,981	290,980	291,270	291,270

5.6 WGCU IGCC PLANT OVERALL SULFUR BALANCE

The overall process sulfur balance for the two WGCU IGCC plants is shown in Table 5.6.. Depending on the coal properties, approximately 5% of the sulfur in the coal feed could be left in the slag and ashes as inert SO_4 solids. For this study, all (100%) of the sulfur in the coal feed is assumed to be converted into H_2S and COS in the syngas, within the gasification unit. Syngas sulfur recovery in the downstream WGCU exceeds 99%+.

Table 5.6
WGCU IGCC Plant Overall Sulfur Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVERALL SULFUR BAL, LB/HR:	IN	OUT	IN	OUT
Coal Feed	21,346	0	11,419	0
Slag and Fine Ash	0	0	0	0
Sulfur Product from SRU	0	21,337	0	11,411
TGTU Incinerator Vent	0	0	0	0
GTCC HRSG Exhaust	0	9	0	9
Total Sulfur, LB/Hr	21,346	21,346	11,419	11,419

5.7 WGCU IGCC PLANT OVERALL STEAM BALANCE

Tables 5.7 to 5.11 list the overall steam balance for the two WGCU IGCC plants.

Integration of the WGCU process into the IGCC produces a large amount of saturated HHP steam that is sent onto the HRSG unit for superheating. As result of the additional superheating duty and the additional HP BFW preheating duty, the HRSG in the WGCU IGCC design is basically a single pressure level HHP steam superheater. As shown in Tables 5.9 and 5.11, MP and LP steam generation by the HRSG are essentially nil for the WGCU IGCC design.

Also, the WGCU IGCC plant does not normally need 650 psig HP steam since there is no COS hydrolysis feed preheat and no GT fuel gas preheat requirement. The only need for 650 psig HP steam will be process equipment purge during emergencies.

Table 5.7
Overall High High Pressure (Nominal 1700 psig 1000 °F) Steam Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
HHP Steam, 1700 PSIG, 1000 F:				
Gasification	930	0	914	0
WGCU/DSRP Generation	510	0	481	0
HRSG	217	0	321	0
HP Stm Turbine Feed	0	1,618	0	1,690
HHP Stm Letdown to HP Stm	0	0	0	0
HHP Stm Letdown to IP Stm	0	39	0	27
TOTAL HHP STEAM, LB/Hr	1,657	1,657	1,716	1,716

Table 5.8
Overall High Pressure (Nominal 650 psig 500 °F) Steam Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
HP Steam, 650 PSIG, 500 F:				
COS Hydroly, Shift & LTGC	0	0	0	0
GT Fuel Gas Preheater	0	0	0	0
WGCU/DSRP Generation	0	0	0	0
WGCU/DSRP Consumption	0	0	0	0
Letdown from HHP Stm	0	0	0	0
Letdown Desuperheat	0	0	0	0
TOTAL HP STEAM, LB/Hr	0	0	0	0

Table 5.9
Overall Medium Pressure (Nominal 450 psig 1000 °F) Steam Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
MP Steam, 450 PSIG, 1000 F:				
HP Stm Turbine Exhaust	1,618	0	1,690	0
HRSG	9	0	5	0
MP Stm Turbine Feed	0	1,627	0	1,694
TOTAL MP STEAM, LB/Hr	1,627	1,627	1,694	1,694

Table 5.10
Overall Intermediate Pressure (Nominal 300 psig 500 °F) Steam Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
IP Steam, 300 PSIG, 500 F:				
ASU	0	15	0	15
WGCU/DSRP Generation	0	0	0	0
WGCU/DSRP Consumption	0	33	0	18
Letdown from HHP Stm	39	0	27	0
Letdown from HP Stm	0	0	0	0
Letdown to LP Stm	0	0	0	0
Letdown Desuperheat	8	0	6	0
TOTAL IP STEAM, LB/Hr	48	48	33	33

Table 5.11
Overall Low Pressure (Nominal 60 psig 550 °F) Steam Balance

	CASE 2 WGCU IGCC 2004 NETL	CASE 2 WGCU IGCC 2004 NETL	CASE 4 WGCU IGCC 2006 NETL	CASE 4 WGCU IGCC 2006 NETL
OVRALL STM BAL, 1000 LB/HR:	Production	Consumption	Production	Consumption
LP Steam, 60 PSIG, 551 F:				
HRSG	13	0	5	0
WGCU/DSRP Generation	87	0	46	0
WGCU/DSRP Consumption	0	0	0	(0)
SWS Consumption	0	14	0	(9)
Letdown from IP Stm	0	0	0	0
STG Extraction Steam	2	0	47	0
STG Extraction Desuperheat	0	0	0	0
BOP (Deaerator Makeup)	0	88	0	89
TOTAL LP STEAM, LB/Hr	102	102	98	98

5.8 WGCU IGCC PLANT OVERALL PROCESS WATER BALANCE

Table 5.12 presents the overall process water breakdown and balance for the two WGCU IGCC plants. Process water balance only accounts for water that entered into or exited from process streams, including reaction formed or consumed water. It does not include water which do not directly mixed with process streams, such as steam, condensate, and cooling water to and from heat exchangers. The overall plant water balance, which includes both process and non-process related water, is shown in Table 5.13 in the next section.

The main process water usage is to meet coal slurry preparation and gasifier makeup needs. The major discharges are water containing in the slag and ash solid wastes.

Table 5.12
WGCU IGCC Overall Process Water Balance

	CASE 2 2004 NETL WGCU	CASE 2 2004 NETL WGCU	CASE 4 2006 NETL WGCU	CASE 4 2006 NETL WGCU
OVERALL PROC H2O BAL, LB/HR:	Production	Consumption	Production	Consumption
AR Coal Feed	38,273	0	50,664	0
Slurry Water	216,856	0	183,106	0
Slag/Ash to Disposal	0	79,732	0	51,489
Gasifier Rx H2O	0	97,754	0	89,511
Gasifier MU H2O	79,732	0	51,489	0
Gasifier Purge H2O	0	0	0	0
COS Hydroly Rx H2O	0	0	0	0
LTGC Condensate	0	0	0	0
RTI Fluidization N2	0	0	0	0
Treated Syngas from AGR	0	180,473	0	156,611
SRU/TGTU Comb & Rx H2O	23,097	0	12,352	0
Treated Syngas to GTCC	180,473	0	156,611	0
Suppl't NG to GTCC	0	0	0	0
Comb Air to GTCC	44,379	0	44,379	0
GTCC HRSG Exhaust	0	466,511	0	460,917
GT Comb Rx Water	241,659	0	259,927	0
TOTAL PROCESS WATER, LB/Hr	824,469	824,469	758,527	758,527

5.9 WGCU IGCC PLANT OVERALL WATER BALANCE

The WGCU IGCC plant imports approximately 4500 gpm of raw makeup water for Case 2 and 4300 gpm for Case 4, mainly for BFW/Process/Plant/Potable Water and Cooling Tower consumption. Table 5.13 presents the estimated water consumption breakdown and balance for the two WGCU IGCC plants.

Because the use of a dry HCl removal process, there is no raw water makeup demands for gasifier chloride purge. Roughly 75% of the raw water import is used for cooling tower makeup.

Approximately 1100 gpm of treated effluent will be discharged from the plant, for both WGCU IGCC plants. The effluent consists of approximately 50% cooling tower blowdown, 25% of raw water treating purge, and 25% of other miscellaneous purges.

Table 5.13
WGCU IGCC Overall Plant Water Balance

	CASE 2 2004 NETL WGCU	CASE 2 2004 NETL WGCU	CASE 4 2006 NETL WGCU	CASE 4 2006 NETL WGCU
OVERALL PLT H2O BAL, LB/HR:	Production	Consumption	Production	Consumption
Water in AR Coal Feed	38,273	0	50,664	0
Slag/Ash to Disposal	0	79,732	0	51,489
Gasifier Purge to SWS/WWT	0	0	0	0
Gasifier Rx H2O	0	97,754	0	89,511
COS Hydroly Rx H2O	0	0	0	0
AGR H2O Purge to SWS	0	0	0	0
Water in Treated Syngas	0	180,473	0	156,611
Water in Acid Gas to SRU	0	0	0	0
Proc Stm Cond Purge to WWT	0	2,357	0	1,340
Steam Syst Cond Purge to WWT	0	81,264	0	82,352
Boiler Blowdowns to WWT	0	14,775	0	15,609
Deaerator Vent	0	200	0	200
CT Evaporatn & Drift Losses	0	1,349,307	0	1,354,122
CT Blowdowns	0	288,678	0	295,666
Potable Water to Sewer	0	2,083	0	2,083
Plant Water to Sewer	0	20,000	0	20,000
Raw Water Treat Purge to WWT	0	132,650	0	125,682
Raw H2O Import by difference	2,221,000	0	2,144,000	0
Total Plant Water, LB/Hr	2,249,273	2,249,273	2,194,664	2,194,664
GPM Raw H2O Import	4,422		4,288	

The above overall water balance assumed the following:

- 5 cycles of cooling tower concentration;
- 70% cooling tower heat regeneration via evaporation;
- 20°F cooling water temperature rise;
- Drift losses at 0.001% of circulation rate;
- Approximately 85% RO/ Demin recovery
- 5% condensate purge;
- 95% raw water treating recovery;
- No recycle or re-claim treated waste water to minimizing water usage;

5.10 WGCU IGCC PLANT OVERALL POWER BALANCE

The 600 MWe WGCU IGCC plant has a net power export of 589 MWe when using the 2004 NETL coal as feed, and 641 MWe with the 2006 NETL design coal feed. Table 5.14 shows the breakdown of the overall power balance for the two plants. The GT power output is representative of 60 ^oF ambient temperature operation, at the project site elevation.

The GT output is about 7.8% higher for Case 4 as compared to Case 2. The increase is the result of its higher total fuel gas LHV (about 7%, see Section 5.11 WGCU IGCC Overall Fuel Gas Balance); Case 4 2006 coal feed has a lower sulfur content, and it consumes less syngas in its DSRP sulfur recovery process.

Steam turbine-to-GT output is lower for Case 4 compared to Case 1. The expected Case 4 steam turbine output if pro-rated directly from Case 1 is (300.3 / 416.8) x 449.3 = 324 MWe, or 7 MWe higher than what is shown in Table 5.14. This 7 MWe lower steam turbine output for Case 4 is due to reduced WGCU HHP saturated steam generation from burning less fuel gas to recover the smaller amount of sulfur. The fuel saving is converted to GT output, as discussed above.

Table 5.14
WGCU IGCC Plant Overall Power Balance

	CASE 2 2004 NETL Illinois #6	CASE 4 2006 NETL Illinois #6
GENERATION, MWe:		
Gas Turb Generator System	416.8	449.3
Steam Turb Generator System	300.3	316.7
Total Gross Output	717.1	766.0
CONSUMPTION, MWe:		
Coal Handling/Storage	5.6	5.1
Gasification/Feed Prep	4.4	2.8
Air Separation	42.1	41.1
O2 Compression	24.8	24.2
COS Hydrolysis & LT Gas Cooling	---	---
Acid Gas Removal & SWS	---	---
Sulfur Recovery	---	---
RTI Warm Gas Clean Up/DSRP	11.5	6.1
CO2 Dehydr'n & Comp	---	---
Plt Air/Instru Air/N2 System	11.8	17.3
HRSG/Boiler Plt/BFW/DM/Cond	8.0	7.9
CW Pumps & CT Fans	8.2	8.1
Flue Gas CO2 Recovery	---	---
BOP	11.7	12.4
Total Consumption	127.9	125.1
NET POWER EXPORT, MWe	589.2	640.9

5.11 WGCU IGCC PLANT OVERALL FUEL GAS BALANCE

Table 5.15 lists the estimated overall fuel gas balance for the two WGCU IGCC plants. Pilot natural gas consumption (approximately 1 to 3% of net process gas fired LHV) is not included in the balance. The balance also does not include offsite sour flare header/stack syngas or natural gas purge consumptions.

While the same volume of syngas is produced in the 1800 ft^3 GE gasifiers (constant residence time), raw syngas LHV is about 2.5% higher for Case 4. This difference reflects the impact of burning more moisture-ash-free (MAF) coal to vaporize more water in the slurry feed for Case 2, as shown by its higher water-to-MAF coal ratio.

Treated syngas LHV available to the gas turbines is 7% higher for Case 4 after deducting WGCU/DSRP fuel demands. This increase in available LHV reflects the impact of lower sulfur content of the Case 4 feed coal (2006 NETL Illinois #6) resulting in less fuel gas consumption for sulfur recovery.

Table 5.15
WGCU IGCC Plant Overall Fuel Gas Balance

	CASE 2 2004 NETL Illinois #6	CASE 2 2004 NETL Illinois #6	CASE 4 2006 NETL Illinois #6	CASE 4 2006 NETL Illinois #6
OVERALL FUEL GAS BAL, MMBtu(LHV)/Hr:	Production	Consumptions	Production	Consumptions
Raw Syngas from Radiant Cooler	3,701	0	3,795	0
Import Natural Gas	0	0	0	0
Syngas in Quench Water	0	0	0	0
COS Hydrolysis Reaction Loss	0	0	0	0
WGCU/DSRP	0	309	0	165
Acid Gas to SRU	0	0	0	0
Treated Syngas to TGTU Rx & Incinerator	0	0	0	0
Treated Syngas to GT	0	3,392	0	3,630
TOTAL Fuel Gas LHV, MMBtu/Hr	3,701	3,701	3,795	3,795
Syngas Flow Exit Gasifiers, Actual Ft^3/sec	743		741	

5.12 PLANT COOLING WATER AND AIR COOLER LOADS

Table 5.16 summarizes the WGCU IGCC plant cooling water (CW) and air cooler (AC) cooling loads for Case 2 and Case 4. Roughly 80% of the total CW load is attributable to the STG surface condenser. Split between CW and AC is based on air cooling to 140 ^oF before switching to water cooling,

Table 5.16
Reference IGCC Plant Cooling Loads

	CASE 2 2004 NETL WGCU	CASE 2 2004 NETL WGCU	CASE 4 2006 NETL WGCU	CASE 4 2006 NETL WGCU
OVERALL COOLING LOADS, MM:	CW	Air Cool	CW	Air Cool
ASU/O2 Comp	342		344	
Gasification (Ash & Purge H2O Cool)	59		38	
COS Hydrolysis & LTGC	0	(0)	0	0
AGR	0	0	0	0
WGCU/DSRP	37		20	
SRU/TGTU	0		0	
SWS		18		12
STG Surface Cond	1,511		1,549	
Offplot CW Demands	8		7	
Total Cooling Load, MMBtu/Hr	1,956	18	1,958	12

5.13 ESTIMATED CATALYST AND CHEMICALS CONSUMPTION

The estimated overall catalyst and chemical (C&C) consumption for the 600 MWe WGCU IGCC plants is approximately $10 MM for Case 2 and $15 MM for Case 4.

5.14 ESTIMATED CAPITAL COST AND BASIS

Table 5.18 presents the estimated installed costs of the two WGCU IGCC plants, listed by individual units. Costs shown are capacity factored estimates based on Nexant's in-house data with an accuracy of +/- 30%. For the WGCU/DSRP plant cost, RTI provided the major equipment designs from which Nexant developed the December 2006 major equipment factored capital cost using commercial estimation software (ICARUS from Aspen), supplemented with in-house data.
Description of the cost estimation basis is included in Section 4.14 of this report.

A $6MM SCR allowance is added to the HRSG cost to cover the need of SCR to reduce net NO_x in the GT exhaust to below 15 ppmV.

Table 5.18
2006 WGCU IGCC Plant Capital Cost, $1,000,000

	CASE 2 2004 NETL Illinois #6	CASE 4 2006 NETL Illinois #6
CAPITAL COSTS, 2006 $MM		
Coal Handling/Storage	18.4	17.8
Gasification/Feed Prep	159.0	151.5
Spare Gasifiers	79.5	75.8
Air Separation	84.6	83.2
O2 Compression	Incl in ASU	Incl in ASU
COS Hydroly, Shift & LTGC	---	---
Acid Gas Removal & SWS	5.8	4.3
Sulfur Recovery	---	---
Tail Gas Treating Unit	---	---
RTI Warm Gas Clean Up/DSRP	196.8	164.1
CO2 Dehydr'n & Comp	---	---
Plt Air/Instru Air/N2 System	11.6	15.0
Gas Turb Generator System	137.5	145.0
HRSG/Boiler Plt/BFW/DM/Cond	54.5	55.6
Steam Turb Generator System	54.1	56.1
CW Pumps & CT Fans	18.2	18.5
Flue Gas CO2 Recovery	---	---
BOP	165.8	168.8
Total Installed Cost	985.7	955.4
Home Office Cost	98.6	95.5
Contingency	0.0	0.0
Total Plant Cost	1,084.3	1,050.9

5.15 ESTIMATED OPERATING COST AND ASSUMPTIONS

Table 5.19 shows the itemized annual operating cost (incomes and expenses) for the Case 2 and Case 4 WGCU IGCC plant. The operating cost is based on an annual overall on-stream factor (equivalent availability) of 85%.

Description of the operating cost estimate basis is included in Section 4.15 of this report.

Table 5.19
WGCU IGCC Plant Annual Operating Costs, $1,000,000/Year

	CASE 2 2004 NETL Illinois #6	CASE 4 2006 NETL Illinois #6
INCOMES & EXPENSES, $MM/Yr:		
AR Coal Cost	78.7	79.2
Raw Water Import	0.7	0.7
Cat & Chem Consumptn	10.0	15.0
Royalties	0.0	0.0
Mainten Labor & Mat	32.4	31.4
Admin & Labor Salary	14.4	14.4
Overheads & Benefits	5.0	5.0
Insurances	10.8	10.5
Local Taxes	10.8	10.5
Sulfur Sale	(5.6)	(3.0)
Ash & Slag Disposal	2.7	1.7
Waste Water Disposal	0.0	0.0
CO2 Sequestn Credit	0.0	0.0
CO2 Emission Penalty	0.0	0.0
Bank Loan Repayment	95.4	92.6
Investment Recovery	52.5	51.0
Total Annual Expenditure	307.8	309.0
Annual Power Export, MW-Hr	4.387,180	4,772,880
Cost of Electricity, ¢/kW-Hr	7.02	6.47

Chapter 6 Reference IGCC and WGCU Performance and Cost Comparison

6.1 OVERALL PLANT CONFIGURATION COMPARISON

Figure 6.1 shows two simple IGCC block flow schemes; comparing the differences in process configuration between a Selexol based Reference IGCC design versus a RTI WGCU based IGCC design. The main difference is in the AGR+SRU+TGTU process selection. For the Reference IGCC design, Selexol is the AGR process, Claus is the SRU, and SCOT is the TGTU being used. For the WGCU IGCC design, RTI's HTDS is the AGR process and HP DSRP is the SRU. TGTU is not required for the WGCU IGCC because DSRP recycles its tail gas back into the syngas feed stream for disposal. Following is a list of key process selection that contributed to the overall performance and cost differences between the Reference and the WGCU IGCC plant.

Reference IGCC	WGCU IGCC
Syngas Quench/COS Hydrolysis/LTGC	HT Convective Feed Cooler
Selexol AGR/Claus SRU/SCOT TGTU	HT Treated Syngas Cooler
LT Mercury Removal	RTI ZnO HTDS AGR/DSRP
Wet Chloride Removal	HT Mercury Removal
	Dry Chloride Removal

Syngas Cooling Scheme Difference

For the Reference IGCC, the 1300 ^{o}F syngas from the GE Gasifier Radiant Cooler is scrubbed and quenched with water down to about 400 ^{o}F for removal of entrained fly ashes, hydrogen chloride, and other soluble trace contaminants. The scrubbed and quenched syngas is superheated with HP steam before going to the COS hydrolysis reactor where 99% of the COS is converted into H_2S to allow the downstream Selexol AGR to produce a clean syngas with 10 ppmv sulfur. The COS hydrolysis reactor effluent is cooled by heat exchanging with the heat-treated syngas feed to the GT, preheat deaerator makeup water (MUW), air cooler, and finally with cooling water to near 100 ^{o}F before going to the Selexol AGR system. The only energy recovered is the treated syngas reheat duty, and the deaerator MUW preheat duty. For maximum efficiency, the GE Radiant Cooler should be followed by a convective cooler to cool the syngas down to 650 ^{o}F by generating more HHP saturated steam before being scrubbed and quenched with water. GE currently does not offer the option for full heat recovery gasification with convective coolers.

Due to its heat integration, the WGCU IGCC design has no heat losses between the radiant cooler exit and the GT inlet, and is expected to be more efficient than the Reference IGCC.

Because the WGCU syngas is not cooled below its water dew point temperature, it retains all the moisture from the gasifier, plus the additional water generated in the HTDS/DSRP reactions.

This moisture helps with reducing the amount of diluent nitrogen injection needed (and thus lower the nitrogen compression power consumption and cost) with meeting the 160 Btu(LHV)/SCF GT fuel specification used by this study.

Because the WGCU syngas will be hot and not scrubbed with water, ammonia (NH_3) in the syngas from the gasifier cannot be removed. This ammonia content may cause the GT exhaust NOx concentration to exceed the study limit of 15 ppmv, even with low NOx burners for the GT. Thus, allowance for SCR is included for the WGCU IGCC design.

Sulfur Recovery Reaction Chemistry Demands

There are some efficiency differences inherent in the reaction chemistry between the Reference IGCC and the WGCU IGCC sulfur recovery technology.

The reaction chemistry for the Reference IGCC's Claus SRU & SCOT TGTU processes are listed below assuming 95% Claus conversion and 100% excess air for SCOT combustion:

$1\ H_2S + 1.5\ O_2 \rightarrow 1\ SO_2 + 1\ H_2O$	Claus Combustion
$2.15\ H_2S + 1\ SO_2 \rightarrow 3\ S + 2\ H_2O + 0.15\ H_2S$	Claus Catalytic Conversion
$3.15\ H_2S + 1.5\ O_2 \rightarrow 3\ S + 3\ H_2O + 0.15\ H_2S$	Overall Claus Reaction
$0.15\ H_2S + 0.45\ O_2 \rightarrow 0.15\ SO_2 + 0.15\ H_2O + 0.225\ O_2$	SCOT Recycle Combustion
$0.15\ SO_2 + 0.45\ H_2 \rightarrow 0.15\ H_2S + 0.3\ H_2O$	SCOT SO_2 Reduction
$0.225\ O_2 + 0.45\ H_2 \rightarrow 0.45\ H_2O$	SCOT Excess O_2 Reduction
$0.15\ H_2S + 0.9\ H_2 + 0.45\ O_2 \rightarrow 0.15\ H_2S + 0.9\ H_2O$	Overall SCOT Reactions
$3\ H_2S + 0.9\ H_2 + 1.95\ O_2 \rightarrow 3\ S + 3.9\ H_2O$	Overall Claus/SCOT Rx (exclude tail gas incineration)

As shown in the above reactions, the Reference IGCC's SCOT TGTU consumes roughly 0.3 moles of H_2 (or the same amount of CO, which will generate CO_2 instead of H_2O as byproduct) for every mole of sulfur recovered by the Claus SRU, excluding tailgas incineration supplemental fuel consumption. SCOT tailgas incineration for Claus SRU feeding 25% H_2S acid gas requires approximately another 0.5 mole of H_2 (or CO) per mole of sulfur recovered. Therefore, total H_2 (or CO) consumed by the Reference IGCC sulfur removal and recovery processes is approximately 0.8 mole per mole of sulfur recovered.

The reaction chemistry for the WGCU IGCC HTDS/DSRP sulfur recovery processes are listed below assuming no excess oxygen for HTDS Regeneration and 98% DSRP conversion:

$1.02\ H_2S + 1.02\ ZnO \rightarrow 1.02\ ZnS + 1.02\ H_2O$	HTDS Absorption
$1.02\ ZnS + 1.53\ O_2 \rightarrow 1.02\ ZnO + 1.02\ SO_2$	HTDS Regeneration
$1.02\ SO_2 + 2.04\ H_2 \rightarrow 1.02\ S + 2.04\ H_2O$	DSRP Catalytic Conversion
$0.02\ S + 0.02\ H_2 \rightarrow 0.02\ H_2S$	DSRP Recycle S Reduction
$1\ H_2S + 1.53\ O_2 + 2.06\ H_2 \rightarrow 1\ S + 3.06\ H_2O$	Overall HTDS/DSRP Rx

As shown, the WGCU IGCC's HTDS/DSRP process consumes roughly 2.06 moles of H_2 (or the same amount of CO, which will generate CO_2 instead of H_2O as byproduct) for every moles of sulfur recovered. No tail gas incineration is required for the WGCU IGCC.

Therefore, the new RTI HTDS/DSRP technology consumes approximately two times the syngas used by the conventional Claus SRU/SCOT TGTU technology for sulfur recovery. Chemistry differences between the two sulfur recovery technologies can significantly impact the overall IGCC performance by reducing the net fuel gas heating value available to the GT, especially for high sulfur coals.

The RTI WGCU process recycles all of the pressurized tail gas leaving the DSRP back into the raw syngas feed, and in doing so, increases the syngas CO_2 and H_2O content. This has the benefit of reducing the amount of diluent nitrogen needed with meeting the GT fuel gas LHV specification. The diluent nitrogen reduction lowers the nitrogen compression power consumption and costs.

Mercury Removal

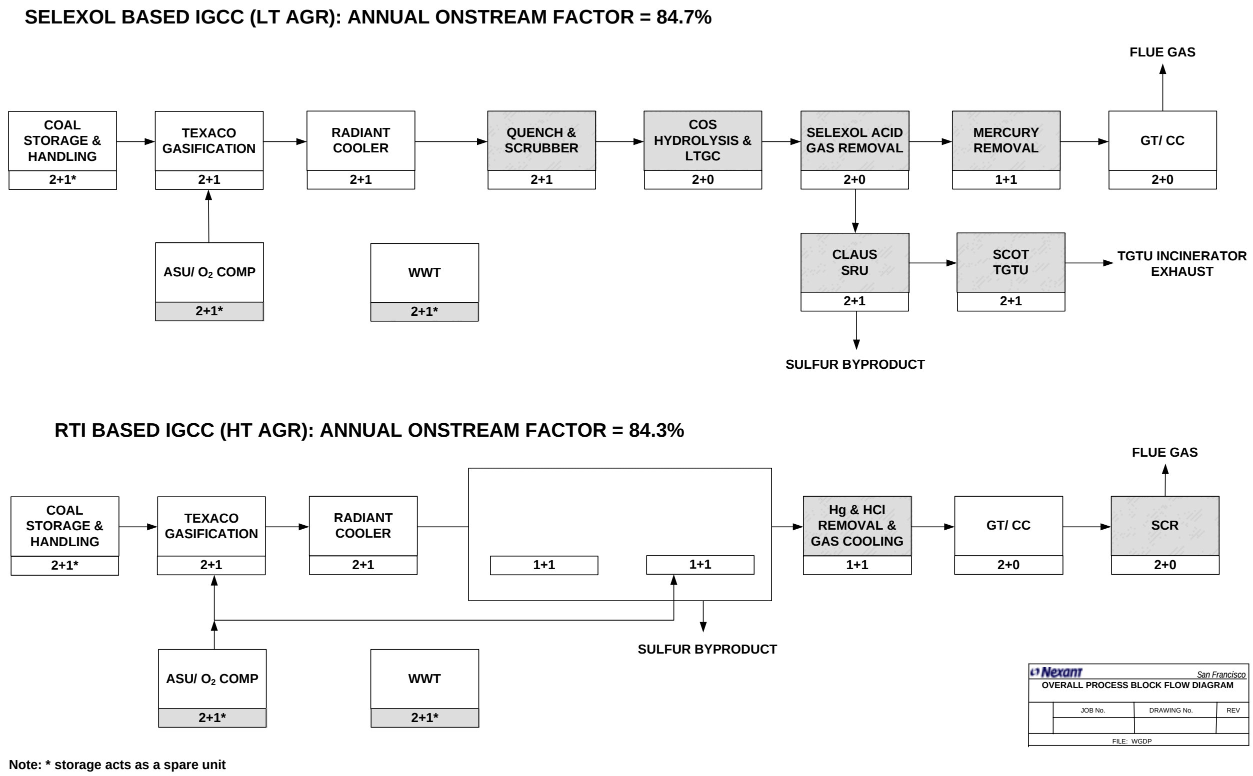
Using RTI's proprietary high temperature (HT) mercury removal technology allows the WGCU IGCC to deliver the treated syngas to the GT at 550 ^oF. By delivering the gas hot to the GT, the WGCU IGCC design retains its efficiency advantage over the Reference IGCC design because of less N_2 diluent needed, and not rejecting any energy to the atmosphere.

Chloride Removal

As with mercury removal, the use of solid adsorbent to remove HCl at 550 ^oF allows the WGCU to retain its efficiency advantage over the Reference IGCC as mentioned above. In addition, the solid adsorbent technology also eliminates the need for large SWS (sour water stripping) plant to treat the sour chloride purge water. Reducing the amount of LP steam used in the SWS reboiler increases the WGCU IGCC steam turbine output, and further increase the WGCU IGCC overall efficiency.

Figure 6.1

Overall BFD for Reference IGCC & WGCU IGCC



6.2 OVERALL DESIGN CONDITION COMPARISON

Table 6.1 lists the design condition of the four IGCC cases evaluated in this study. Because of the low gas turbine exhaust gas temperature (EGT), the MP steam reheat temperature for Case 2 is lowered to 950 ^oF.

Table 6.1
Overall Design Conditions Comparison

	CASE 1 Reference IGCC 2004 NETL Coal	CASE 2 WGCU IGCC 2004 NETL Coal		CASE 3 Reference IGCC 2006 NETL Coal	CASE 4 WGCU IGCC 2006 NETL Coal
AR COAL PROPERTIES:					
Ultimate Analysis, Wt%					
Carbon	60.42			63.75	
Hydrogen	3.89			4.50	
Nitrogen	1.07			1.25	
Sulfur	4.45			2.51	
Oxygen	7.91			6.88	
Chloride	0.05			0.29	
Ash	14.25			9.7	
Moisture	7.97			11.12	
Total Wt%	100.00			100.00	
HHV, Btu/lb	10,999			11,666	
GASIFIER TYPE	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F		2+1 x 1800 Ft^3 GE @ 550 # & 2450 F	2+1 x 1800 Ft^3 GE @ 550 # & 2450 F
SLURRY FEED, Wt% MF Coal	63.4	63.4		63.4	63.4
SLURRY LB H2O / LB MAF COAL	0.683	0.683		0.648	0.648
SYNGAS COOLING – High Temp	Radiant to 1300 ^oF	Radiant to 1300 ^oF		Radiant to 1300 ^oF	Radiant to 1300 ^oF
SYNGAS COOLING – Low Temp	Quench/AC/CW To 90 ^oF	Convective to 550 ^oF		Quench/AC/CW To 90 ^oF	Convective to 550 ^oF
MERCURY REMOVAL	90% , LT	90% , HT		90% , LT	90% , HT
CHLORIDE REMOVAL	Wet Scrub	Dry Adsorb		Wet Scrub	Dry Adsorb
ACID GAS REMOVAL	Selexol	WGCU		Selexol	WGCU
CO2 RECOVERY / PRE-INVESTMENT	No	No		No	No
SULFUR RECOVERY	Claus + TGTU	DSRP		Claus + TGTU	DSRP
GAS TURBINE	2 x GE 7FB	2 x GE 7FB		2 x GE 7FB	2 x GE 7FB
GT FUEL LHV, Btu/SCF Incl Diluent	163	164		161	162
GT FUEL GAS LHV, MMBtu/Hr	3,488	3,392		3,680	3,630
FUEL GAS TEMP @ GTCC B/L	340 ^oF	550 ^oF		340 ^oF	550 ^oF
GT EXHAUST GAS TEMPERATURE	1076 ^oF	1055 ^oF		1119 ^oF	1109 ^oF
STEAM TURBINE / HRSG	2 x Re-Heat 1000 ^oF / 1000 ^oF	2 x Re-Heat 1000 ^oF / 950 ^oF		2 x Re-Heat 1000 ^oF / 1000 ^oF	2 x Re-Heat 1000 ^oF / 1000 ^oF

6.3 OVERALL PLANT PERFORMANCE COMPARISON

Table 6.2 shows the overall plant performance comparison of the four IGCC plant designs. As shown, for the same coal feed and gasifier throughput, the WGCU IGCC plant:

- Consumes little bit more 95% oxygen because of HTDS ZnS-to-ZnO regeneration usage;
- Consumes little bit more raw water with low chloride coal to makeup for water loss in Slag and Ash since it is not condensing out the water in the syngas from gasification;
- Consumes lot less raw water with high chloride coal because of its dry HCl removal process does not require water purge to remove chloride;
- Consumes less 99% nitrogen diluent because of not condensing out the water in the syngas from gasification;
- Generates less waste water because of its dry HCl removal process does not require water purge to remove chloride;
- Exports more power because of higher STG output from the additional HHP steam generated by its convective syngas coolers.

Table 6.2
Overall Performance Comparison
(Excluding Chemicals and Catalysts)

	Case 1 Reference IGCC 2004 NETL Coal	Case 2 WGCU IGCC 2004 NETL Coal	Case 3 Reference IGCC 2006 NETL Coal	Case 4 WGCU IGCC 2006 NETL Coal
CONSUMABLES:				
AR Coal Feed,STPD	5,763	5,763	5,467	5,467
Raw Water, GPM	4,227	4,422	5,646	4,288
95.0% O2, STPD	4,576	5,006	4,665	4,895
99% N2, STPD	6,765	2,919	7,024	3,959
NG Import, MMLHV/Hr	0	0	0	0
PRODUCTS:				
Power Export, MWe	558	589	585	641
Sulfur, STPD	255	256	137	137
Slag & Ash, STPD Dry	870	870	562	562
Waste Water, GPM	1,306	1,084	2,798	1,085
Recovered CO2, STPD	(0)	0	(0)	0
OVERALL ELECTRIC EFFICIENCIES:				
Gross Heating Value Basis	36.1 % HHV	38.1 % HHV	37.6 % HHV	41.2 % HHV
Net Heating Value Basis	37.6 % LHV	39.7 % LHV	39.3 % LHV	43.1 % LHV

The slight difference in sulfur product rate is because the WGCU IGCC removes syngas sulfur level down to 5 ppmv vs. 10 ppmv for the Reference IGCC.

Also, relative differences in performance between the Reference IGCC and the WGCU IGCC change as coal feed is changed. Compared to the Reference IGCC, the WGCU IGCC exports 31 MWe more power, which corresponds to a 2 percentage point increase in overall electric efficiency with 2004 NETL #6 Illinois coal. This advantage increases to 56 MWe or a 3.6

percentage point in efficiency when using 2006 NETL design coal. Following is the breakdown on the causes of these efficiency differences:

	WGCU Incremental MWe	
	2004 NETL	2006 NETL
Less Btu(LHV)/Hr to GT for WGCU due to DSRP reactions	- 14	- 6
Higher HHP steam generation from Convective Cooling	+ 39	+ 37
HHP->HP steam letdown for FG & COS Hydroly Fd Preheat	+ 0	+ 2
Less LP Steam to SWS Reboiling due to dry HCl Removal	+ 2	+ 13
Higher 95% O_2 Demand	- 6	- 3
Lower N_2 Compression plus SRU Consumption differences	+ 12	+ 12
Total Estimated Incremental WGCU Power Export, MWe	+ 33	+ 55
Percentage Point Increase in Overall Efficiency	+ 2.0	+ 3.6

As seen from the above breakdown, the major reasons for the increase in efficiency spread going from 2004 NETL coal to 2006 NETL design coal are because of:

- 8 MWe more GT output for WGCU IGCC due to less sulfur recovery reaction fuel consumption for the lower sulfur 2006 coal , and
- 11 MWe less ST output for Reference IGCC due to higher SWS LP steam consumption for the higher chloride 2006 coal.

6.4 OVERALL PLANT POWER BALANCE COMPARISON

Table 6.3 shows the comparison of the overall power balances for the four cases evaluated in this study.

Table 6.3
Overall IGCC Power Balance Comparison

	Case 1 Reference IGCC 2004 NETL Coal	Case 2 WGCU IGCC 2004 NETL Coal	Case 3 Reference IGCC 2006 NETL Coal	Case 4 WGCU IGCC 2006 NETL Coal
POWER BALANCE				
GENERATION, MWe:				
Gas Turb Generator System	430.7	416.8	455.7	449.3
Steam Turb Generator System	260.8	300.3	263.2	316.7
Total Gross Output	691.5	717.1	719.0	766.0
CONSUMPTION, MWe:				
Coal Handling/Storage	5.6	5.6	5.1	5.1
Gasification/Feed Prep	4.4	4.4	2.8	2.8
Air Separation	38.4	42.1	39.2	41.1
O2 Compression	22.6	24.8	23.1	24.2
COS Hydrolysis & LT Gas Cooling	0.9	0.0	0.7	0.0
Acid Gas Removal & SWS	3.0	0.0	2.0	0.0
Sulfur Recovery	1.0	---	0.5	---
RTI Warm Gas Clean Up/DSRP	---	11.5	---	6.1
CO2 Dehydr'n & Comp	0.0	0.0	0.0	0.0
Plt Air/Instru Air/N2 System	30.4	11.8	31.7	17.3
HRSG/Boiler Plt/BFW/DM/Cond	7.3	8.0	8.2	7.9
CW Pumps & CT Fans	8.2	8.1	8.2	8.1
Flue Gas CO2 Recovery	---	---	---	---
BOP	11.5	11.7	12.5	12.4
Total Consumption	133.2	127.9	134.0	125.1
NET POWER EXPORT, MWe	558.3	589.2	585.0	640.9
Syngas to Gas Turb, MMBtu(LHV)/Hr	3,488	3,392	3,680	3,630
Sulfur Recovered, Moles/Hr	664.0	665.5	355.0	355.9
HHP Sat Steam from WGCU, 1000 LB/Hr	0	510	0	481
LP Steam to SWS, 1000 LB/Hr	40	14	166	9

GT output differences are related to the amount of syngas fuel available. While the gasifier syngas generation is constant for a given coal, the net fuel available to the GT varies between the Reference IGCC and the WGCU IGCC due to the different sulfur recovery reaction chemistry (Section 6.1). The WGCU IGCC is more efficient, in comparison, for coal feed with a low sulfur and high chloride content.

Steam turbine output advantages for the WGCU IGCC are mainly due to the use of convective cooler.

6.5 ESTIMATED CAPITAL COST COMPARISON

Table 6.4 shows the comparison of the overall capital costs. These are capacity factored estimates based on Nexant's in-house data with an accuracy of +/- 30%. These are 2006 costs, excluding contingencies. Capital costs for the WGCU/DSRP system included latest vendor quotes for the high pressure, high temperature syngas cyclones plus quotes for the sintered metal filters for solids removal.

Table 6.4
Capital Cost Comparison

	Case 1 Reference IGCC 2004 NETL Coal	Case 2 WGCU IGCC 2004 NETL Coal	Case 3 Reference IGCC 2006 NETL Coal	Case 4 WGCU IGCC 2006 NETL Coal
CAPITAL COSTS, 2006 $MM				
Coal Handling/Storage	18.4	18.4	17.8	17.8
Gasification/Feed Prep	159.0	159.0	151.5	151.5
Spare Gasifiers	79.5	79.5	75.8	75.8
Air Separation	79.4	84.6	80.5	83.2
O2 Compression	Incl ASU	Incl ASU	Incl ASU	Incl ASU
COS Hydroly, Shift & LTGC	36.8	0.0	37.2	0.0
Acid Gas Removal & SWS	131.8	5.8	147.9	4.3
Sulfur Recovery	25.4	0.0	16.4	0.0
Tail Gas Treating Unit	32.3	0.0	20.8	0.0
RTI Warm Gas Clean Up/DSRP	0.0	196.8	0.0	164.1
CO2 Dehydr'n & Comp	---	---	---	---
Plt Air/Instru Air/N2 System	23.1	11.6	23.8	15.0
Gas Turb Generator System	140.7	137.5	146.4	145.0
HRSG/Boiler Plt/BFW/DM/Cond	48.2	54.5	49.0	55.6
Steam Turb Generator System	48.9	54.1	49.2	56.1
CW Pumps & CT Fans	17.2	18.2	16.5	18.5
Flue Gas CO2 Recovery	---	---	---	---
BOP	164.6	165.7	179.9	168.7
Total Installed Cost	1,005.2	985.7	1012.6	955.4
Home Office Cost	100.5	98.6	101.3	95.5
Contingency	0.0	0.0	0.0	0.0
Total Plant Cost	1,105.8	1,084.3	1,113.8	1,050.9
Net Power Export, MWe	558.3	589.2	585.0	640.9
Total Plant Cost per Unit Output, $/KWe	1,981	1,841	1,904	1,640

6.6 ESTIMATED COST OF ELECTRICITY COMPARISON

Table 6.5 shows the comparison of the overall annual operating costs and the equivalent cost-of-electricity for the four cases evaluated in this study.

Table 6.5
Overall Annual Operating Costs and Cost-Of-Electricity Comparison

	Case 1 Reference IGCC 2004 NETL Coal	Case 2 WGCU IGCC 2004 NETL Coal	Case 3 Reference IGCC 2006 NETL Coal	Case 4 WGCU IGCC 2006 NETL Coal
INCOMES & EXPENSES, $MM/Yr:				
AR Coal Cost	78.7	78.7	79.2	79.2
Raw Water Import	0.7	0.7	0.9	0.7
Cat & Chem Consumptn	6.0	10.0	6.0	15.0
Royalties	0.0	0.0	0.0	0.0
Mainten Labor & Mat	33.2	32.4	33.4	31.4
Admin & Labor Salary	14.4	14.4	14.4	14.4
Overheads & Benefits	5.0	5.0	5.0	5.0
Insurances	11.1	10.8	11.1	10.5
Local Taxes	11.1	10.8	11.1	10.5
Sulfur Sale	(5.5)	(5.6)	(3.0)	(3.0)
Ash & Slag Disposal	2.7	2.7	1.7	1.7
Waste Water Disposal	0.0	0.0	0.0	0.0
CO2 Sequestn Credit	0.0	0.0	0.0	0.0
CO2 Emission Penalty	0.0	0.0	0.0	0.0
Bank Loan Repayment	97.3	95.4	98.0	92.6
Investment Recovery	53.6	52.5	53.9	51.0
Total Annual Expenditure, $MM/Yr	308.1	307.8	311.9	309.0
ANNUAL POWER EXPORT, MW-Hr	4,154,868	4,387,180	4,355,910	4,772,880
COST-OF-ELECTRICITY, ¢/kW-Hr	7.42	7.02	7.16	6.47

On-stream Factor Impact:

Annual power export shown in Table 6.5 assumes 85% on-stream factor for all four cases. While the Reference IGCC plant's AGR, SRU and TGTU are all relatively mature technology, RTI's WGCU/DSRP is a new technology not yet commercially demonstrated. It is therefore reasonable for the WGCU IGCC design to have a lower on-stream factor than the Reference IGCC design.

With the estimated cost-of-electricity advantage at constant on-stream factor, the WGCU design should remain competitive with up to 5-to-8 percentage point lower in on-stream factor (77% to 80%)

Based on the overall efficiency, capital cost and cost-of-electricity comparison, the WGCU IGCC technology design appears to be an attractive alternative to the Selexol-based Reference IGCC design. For the two NETL Illinois #6 coal considered by this study, the WGCU IGCC's overall efficiency is 2 to 3.6 percentage points higher than the Reference IGCC. The WGCU IGCC's is $25MM to $65MM cheaper to build. And the cost of electricity is 0.4 to 0.7 ¢/kW-hr less than the Reference IGCC design.

WGCU IGCC performance and cost advantage is heavily depended on the sulfur and chloride contents of the coal feed. High sulfur and low chloride reduces WGCU's advantage, while low sulfur/high chloride increases its advantage over the Reference IGCC design.

The cost advantages mentioned assumes both IGCC designs have the same on-stream factor of 85%. This assumption may be questionable since the Reference IGCC design's AGR, SRU and TGTU are all relatively mature technologies, while RTI's WGCU/DSRP is a yet-to-be-commercially demonstrated new technology. The WGCU/DSRP option would be expected to have lower on-stream factor. Even if lower on-stream factor is assigned to the WGCU IGCC design, it should remain competitive with up to 5-to-8 percentage point lower on-stream factors (77% to 80%).

One of the key uncertainties in the WGCT IGCC design is the successful deployment of a convective syngas feed cooler. In addition to account for two percentage point efficiency improvement between the WGCU and the Reference IGCC, the RTI HTDS/DSRP process depends on this feed cooler to lower the syngas temperature to the required 800 ^{o}F operating range. While GE is not offering a convective cooler design for their gasifier due to unsuccessful past experiences, similar cooler is being offered by the Shell and the Conoco-Philips gasification licensors, which implies that successful convective syngas cooler design and operation are achievable.

Appendix A Acronyms, Abbreviations and Symbols

This section includes acronyms, abbreviations and symbols. In general, company names and product trade names are not included here.

AC	Air Cooler
Admin	Administration
AGR	Acid Gas Removal
AR	As Received
Ar	Argon
ASU	Air Separation Unit
Avg, avg	Average
BBL, Bbl, bbl	Barrel
BD	Blowdown
BFW	Boiler Feed Water
BHP	Brake Horse Power
B/L	Battery Limit
BOP	Balance Of Plant
BPD, b/d, Bbl/d, Bbl/day	Barrels Per Day
BPSD	Barrel Per Stream Day
Btu	British Thermal Unit
°C, Deg C, deg C	Degrees Celsius
CAT	Catalyst
C&C	Catalysts and Chemicals
CC	Combined Cycle
cc	Cubic Centimeter
CF	Cubic Feet
Chem	Chemical
Comb	Combustor, Combustion
Comp	Compressor
Cond	Condensate
Consumptn	Consumption
COS	Carbonyl Sulfide
CT	Cooling Tower
CTL	Coal To Liquid
cu. ft., $ft.^3$	Cubic Feet
CW	Cooling Water
DCS	Distributed Control System
Deg C, deg C, °C	Degrees Celsius
Deg F, deg F, °F	Degrees Fahrenheit
Dehydr'n	Dehydration
Demin	Demineralized
DM	Demineralization
DMPEG	Dimethyl Ethers of Polyethylene Glycol
DOE	U.S. Department of Energy

DSRP	Direct Sulfur Recovery Process
EGT	Exhaust Gas Temperature From Gas Turbine
Exch	Exchanger
Fd	Feed
Ft, ft	Feet
FT, F-T	Fischer-Tropsch
fr	From
GE	General Electric
GPM, gpm	Gallon Per Minute
GT	Gas Turbine
GTG	Gas Turbine General
GTL	Gas-to-Liquid
H&M	Heat and Material
HCl	Hydrogen Chloride
HHP	High High Pressure
HHV	Higher Heating Value
Hg	Mercury
HP	High Pressure, Horse Power
Hr, hr	Hour
HRSG	Heat Recovery Steam Generator
HTDS	High Temperature Desulfurization Process
HTGC	High Temperature Gas Clean Up
Hydroly	Hydrolysis
IGCC	Integrated Gasification Combined Cycle
In, in	Inch
Incl.	Include
IntrStg	Interstage
Instru	Instrumentation
IP	Intermediate Pressure
kg	Kilogram
kW, kWe	Kilowatt
L	Long, Liquid
LB	Pound Mass
LB/Hr, lb/hr, lbs/hr	Pound Mass Per Hour
LHV	Lower Heating Value
LP	Low Pressure
LT	Low Temperature
LTGC	Low Temperature Gas Cooling
LTPD	Long Tons Per Day
M	Meters
M	Motor
MAF	Moisture Ash Free
Mat.	Material
Max	Maximum
MF	Moisture Free
MH	Man Hour
MM	Million
MMBtu/hr	Million British Thermal Unit Per Hour

MMSCFD	Million Standard Cubic Feet Per Day
Mols/Hr	Pound Moles Per Hour
Mol Wt, mol wt	Molecular Weight
MP	Medium Pressure
MPH	Moles Per Hour
MU	Make Up
MUW	Make Up Water
MW, MWe	Megawatt
MW	Molecular Weight
NA, N/A	Not Available, Not Applicable
NETL	National Energy Technology Laboratory
NG	Natural Gas
Nm^3/H	Normal Cubic Meters Per Hour
No., #	Number
NO_x	Nitrogen Oxide
O/U	Offsite/Utilities
P	Pressure
PC	Pulverized Coal Fired
PFD	Process Flow Diagram
pH	Potential of Hydrogen
P&ID	Piping and Instrumentation Diagram
Plt.	Plant
PM	Particulate Matter
PPM, ppm	Parts Per Million
PPMV	Parts Per Million by Volume
PRENFLO	Pressurized Entrained Flow Gasifier (Krupp/Uhde)
Prep	Preparation
Press.	Pressure
PSA	Pressure Swing Adsorption
PSIA, psia	Pounds Per Square Inch, absolute
PSIG, psig	Pounds Per Square Inch, gauge
P&T	Pressure and Temperature
Q	Quarter
Re-Circ	Re-Circulation
Recy	Recycle
ROI	Return On Investment
Rx	Reflux, Reaction
Sat, SAT	Saturated
SatHHP	Saturated High High Pressure
SatMP	Saturated Medium Pressure
SCF	Standard Cubic Feet
SCOT	Shell Claus Tail Gas Treating
SCR	Selective Catalytic Reduction
SMP	Super-Heated Medium Pressure
SRU	Sulfur Recovery Unit
ST	Steam Turbine
STG	Steam Turbine Generator
st/h	Short Tons Per Hour

STM, stm	Steam
STPD, t/d	Short Tons Per Day
Strip	Stripper
SWS	Sour Water Stripper
Temp	Temperature
TGTU	Tail Gas Treating Unit
TIC	Total Installed Cost
TPC	Total Plant Cost
Turb	Turbine
UOP	Universal Oil Products Company
V	Vapor
Vac	Vacuum
Vol.	Volume
WGCU	Warm Gas Clean Up
w/, w	With
w/o, wo	Without
wt	Weight
WWT	Waste Water Treatment
μ	Micro

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