POWER PLANT WATER USAGE AND LOSS STUDY

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LIST OF ACRONYMS AND ABBREVIATIONS

AGR	Acid gas removal
ASU	Air separation unit
BACT	Best available control technology
BFW	Boiler feedwater
Btu	British thermal unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CCT	Clean coal technology
cfm	Cubic feet per minute
CF	Capacity factor
CH_4	Methane
CO_2	Carbon dioxide
COS	Carbonyl sulfide
CSC	Connective syngas cooler
CT	Combustion turbine
CW	Cooling water
CWT	Cold water temperature
DLN	Dry low NOx
DOE	Department of Energy
E-Gas™	Global Energy gasifier technology
EPA	Environmental Protection Agency
EPC	Engineering, procurement, construction
ESP	Electrostatic precipitator
FD	Forced draft
FGD	Flue gas desulfurization
FRP	Fiberglass-reinforced plastic
GE	General Electric
GE R-C	GE Energy Radiant-Convective IGCC
GE Quench	GE Energy Quench IGCC
gpm	Gallons per minute
GT	Gas turbine
h	Hour
H_2	Hydrogen
HHV	Higher heating value

Hg	Mercury
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HWT	Hot water temperature
Hz	Hertz
in. H_2O	Inches water
in. Hga	Inches mercury (absolute pressure)
in. W.C.	Inches water column
ID	Induced draft
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
ISO	International Standards Organization
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
lb	Pound
LHV	Lower heating value
LP	Low pressure
MCR	Maximum coal burning rate
MDEA	Methyldiethanolamine
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MWe	Megawatts electric
MWh	Megawatts-hour
MWt	Megawatts thermal
N_2	Nitrogen
NETL	National Energy Technology Laboratory
N/A	Not applicable
NGCC	Natural gas combined cycle
NH_3	Ammonia
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
O&M	Operations and maintenance
OD	Outside diameter

PA	Primary air
PC	Pulverized coal
PC Sub	Subcritical Pulverized coal system
PC Super	Supercritical Pulverized coal system
pph	Pounds per hour
ppmvd	Parts per million volume, dry
PSD	Prevention of significant deterioration
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
rpm	Revolutions per minute
scfm	Standard cubic feet per minute
RSC	Radiant syngas cooler
SC	Supercritical
SCR	Selective catalytic reduction
SG	Syngas
SO_2	Sulfur dioxide
ST	Steam turbine
TGTU	Tail gas treating unit
tpd	Tons per day
tph	Tons per hour
WB	Wet bulb
wt%	Weight percent

EXECUTIVE SUMMARY

This report was updated in May 2007. The cooling tower evaporative and blowdown losses were overstated in the initial report, and those numbers were modified in this update. All numbers impacted by the change in cooling tower losses were also updated. No other changes were made.

Estimates have been previously made of water usage or water loss for conceptual power plant configurations and have been used as the basis for comparisons of the water impacts of technology options. These previous estimates have been made using available flow sheet data that have generally not been complete, and as a result have generated potentially misleading comparisons. It is important that any comparisons be made using data from complete water balances for the flow sheets and that all uses, makeup streams, discharges, internal generation and losses be accounted for in the balance and assessment of water streams in order to establish credible conclusions.

It is the intent of the study reported here to (1) establish a thorough accounting of water usage throughout the power plant and establish a credible methodology that can be used for future studies, (2) provide a baseline set of cases and water loss data for assessing potential improvements and evaluating R&D programs, and (3) provide a basis for comparing water usage in various types of advanced power systems.

The objective of this study is to prepare a source of information from which valid comparisons can be made for the water loss between the various fossil fuel power plants such as IGCC, PC, and NGCC. The purposes include:

1. Draw valid comparisons on a common basis for (a) various fossil fuel power generation technologies, and (b) different gasification technologies.

2. Provide data to evaluate the water usage and loss issues and identify areas for research and development to reduce water losses.

3. Provide an initial assessment of the potential for reduction in water loss in gasification applications through the use of technology improvements.

The current study has developed the information, methodology, and water accounting systems to enable a credible assessment of water usage and loss in power plant systems. This then achieves objective #1 above. Objectives #2 and 3 can be addressed in future studies using the methodology developed here.

APPROACH

This study is based on a normalized comparison of seven fossil fuel power plants, each designed from a common design basis, nominally producing 500 MWe net. Coal-fired plants used a common coal, and one plant was fired on natural gas. A common mid-USA site was used as the base design plant location with evaporative cooling towers used to reject condenser heat. The plants reviewed included:

- ConocoPhillips E-Gas^{TM} IGCC (E-Gas)
- GE Energy Radiant-Convective IGCC (GE R-C)
- GE Energy Quench IGCC (GE Quench)
- Shell IGCC (Shell)
- Natural Gas Combined Cycle (NGCC)
- Subcritical PC (PC Sub)
- Supercritical PC (PC Super)

PLANT COMPARISONS

For each of the plants, heat and material balances were prepared on a common basis with emphasis on the water usage and loss. The distinction between usage and loss is defined as follows:

Raw Water Usage is defined as the water metered from a raw water source and used in the plant processes for any and all purposes, such as cooling tower makeup, condenser makeup, slurry preparation makeup, ash handling makeup, syngas humidification, quench system makeup, and FGD system makeup. In this study, all plants are equipped with evaporative cooling towers, and all process blowdown streams are assumed to be treated and recycled to the cooling tower. Usage represents the overall impact of the process on the water source.

Water Loss is defined as the water exiting the system and represents the overall "loss" of water to the environment. Such losses can occur as physical losses including process blowdown streams, water entrained in solids, or gas streams vented to the atmosphere, or they can occur through chemical reactions such as gasification shift or hydrolysis. Because water also enters the system with the fuel and ambient air and through combustion reactions, water loss is greater than raw water usage. While the difference between raw water usage and water loss represents the liberation of fuel bound moisture and products of combustion which exit the system and enter the atmosphere, this potential net generation of water resources (water out > water in) is not directly available and is "lost" to the water budget

Water flows, makeup, and points of loss were identified and quantified. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was tracked for each plant and major process area. The cooling tower makeup requirements were separately determined using a consistently applied methodology. Assessing the effects of climatological changes on plant performance and the need for oversizing equipment relative to the standard design have not been addressed in this report but could be considered for future studies.

For each of the seven power plants, the following were prepared:

- Plant Performance Summary

- Heat and Material Balance
- Emission Performance
- Process Block Flow Diagram
- Water Block Flow Diagram
- Overall Water Balance
- Major Plant Sections Water Balance

RESULTS

Water loss results are summarized in Table ES-1. Figure ES-1 shows the results in the form of a bar graph comparing various types of gasifiers. Figure ES-2 shows a comparison of various power plant systems. Water loss is based on an overall balance of the plant source and exit streams. This includes coal moisture, air humidity, process makeup, cooling tower makeup (equivalent to evaporation plus blowdown), process losses (including losses through reactions, solids entrainment, and process makeup/blowdown) and flue gas losses.

The raw water usage in this study is defined as the total amount of water to be supplied from local water resources to provide for the needs of the plant. Raw water usage differs from water loss. The difference is attributable to water entering the system via humid air intake, water content of the fuel, and water produced in gasification/combustion reactions. For example in the cooling tower, the raw water usage is makeup to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage can be the determining factor for plant siting and permitting, as it may have a significant impact on local water availability. The results of the raw water usage calculations are summarized as a bar graph in Figure ES-3.

Process losses are more pronounced with the IGCC plants due to the need to add water to the gasification reactions and promote shift to hydrogen and carbon dioxide. There are no process losses with the NGCC plant. PC plant process losses are confined to water lost with disposal of the FGD gypsum cake. The process losses in each of the systems are the smallest category of loss.

Flue gas losses vary with the type of power plant and the methodology for conditioning either the syngas or the flue gas. Each of the IGCC plants has syngas humidification for NOx mitigation. All of the gasification cases utilize nitrogen injection to dilute the syngas, and the E-Gas and Shell cases have supplemental steam dilution along with the nitrogen dilution. This can be seen in the variations of flue gas water losses for the IGCC gas turbines. The NGCC does not utilize natural gas humidification before firing in the GT combustor; however, the flue gas losses are indicative of the water produced from the air and fuel. The PC power plants each have FGD. These wet processes result in significant water losses to the flue gas from evaporation.

Eighty to ninety-nine percent of the power plant raw water usage is through a combination of cooling tower evaporation and blowdown. This water usage is based on a generic site and assumed cooling tower performance characteristics (see Section 1.3.3). Cooling tower performance as a function of plant condenser duty (plus 100 MMBtu/h of auxiliary load) was assumed for each power plant. Water loss differences are associated with plant condenser duty which can be traced back to plant efficiency and other uses of condensing steam such as methods of syngas humidification or syngas dilution.

SUGGESTED FUTURE WORK

This study consists of the initial phase of an effort to thoroughly document the use of water in power plants, particularly in IGCC applications. The plant configurations used here are based on current commercial offerings and on rigorous systems analysis results. The sites are generic middle USA and water for process and cooling makeup is readily available. There were no economic analyses performed.

- The plant designs from this study can be used as a baseline for conducting additional systems analysis. This analysis would be based upon such design changes as location, water use limitations, and plant efficiency. Changes in process design could also determine the sensitivity to water loss.
- This report should provide some basis for reviewing the design assumptions, technology capabilities, system performance, etc. and identify areas where new technology approaches or gasifier designs could lead to substantially lower water requirements. In turn, this can be a tool for planning R&D and gaining acceptance of out-of-the-box proposals for R&D projects.

Table ES-1
Water Loss Summary, gallons per MWh

	E-Gas gal/MWh	Shell gal/MWh	GE R-C gal/MWh	GE Quench gal/MWh	NGCC gal/MWh	PC Sub gal/MWh	PC Supe gal/MWh
Process losses							
Coal drying moisture		3.3					
Water lost in gasification shift	11.1	6.0	16.7	18.2			
Ash quench blowdown	8.7	7.8	8.4	9.3			
Water with slag	3.0	3.7	3.3	3.7			
Water lost in COS hydrolysis	0.0	0.2	0.0	0.1			
Sour water blowdown	3.1	4.5	0.5	2.5			
Water with gypsum						9.3	8.3
Total	**26**	**25**	**29**	**34**	**0**	**9**	**8**
Flue gas losses							
GT flue gas	105.5	75.3	78.0	104.8	87.0		
Incinerator flue gas		1.5					
Boiler flue gas						107.0	94.8
Total	**106**	**77**	**78**	**105**	**87**	**107**	**95**
Cooling water losses							
Cooling tower blowdown	75.3	85.1	86.1	92.9	70.6	149.4	133.9
Cooling tower evaporation	225.9	255.5	258.5	278.9	212.0	448.5	401.9
Total	**301**	**341**	**345**	**372**	**283**	**598**	**536**
Grand Total	***433***	***443***	***452***	***510***	***370***	***714***	***639***

Figure ES-1
IGCC Water Loss Summary for Various Gasifier Types, gallons per MWh

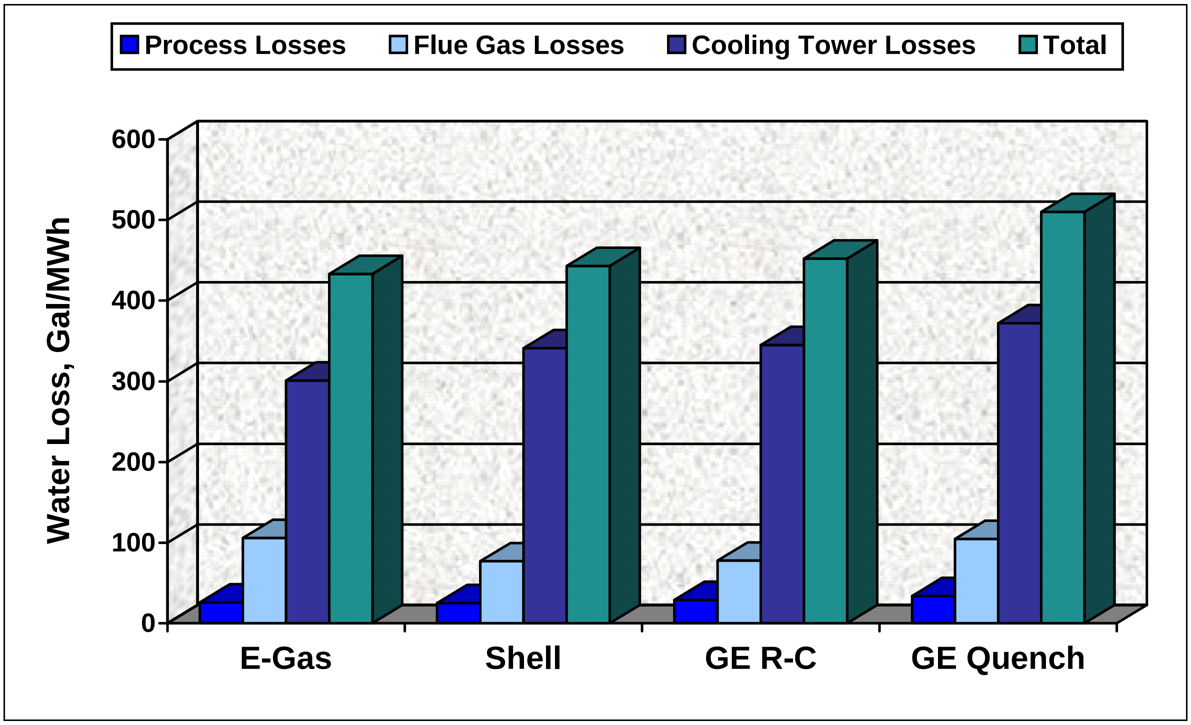


Figure ES-2
Comparison of Water Loss for Various Fossil Plants, gallons per MWh

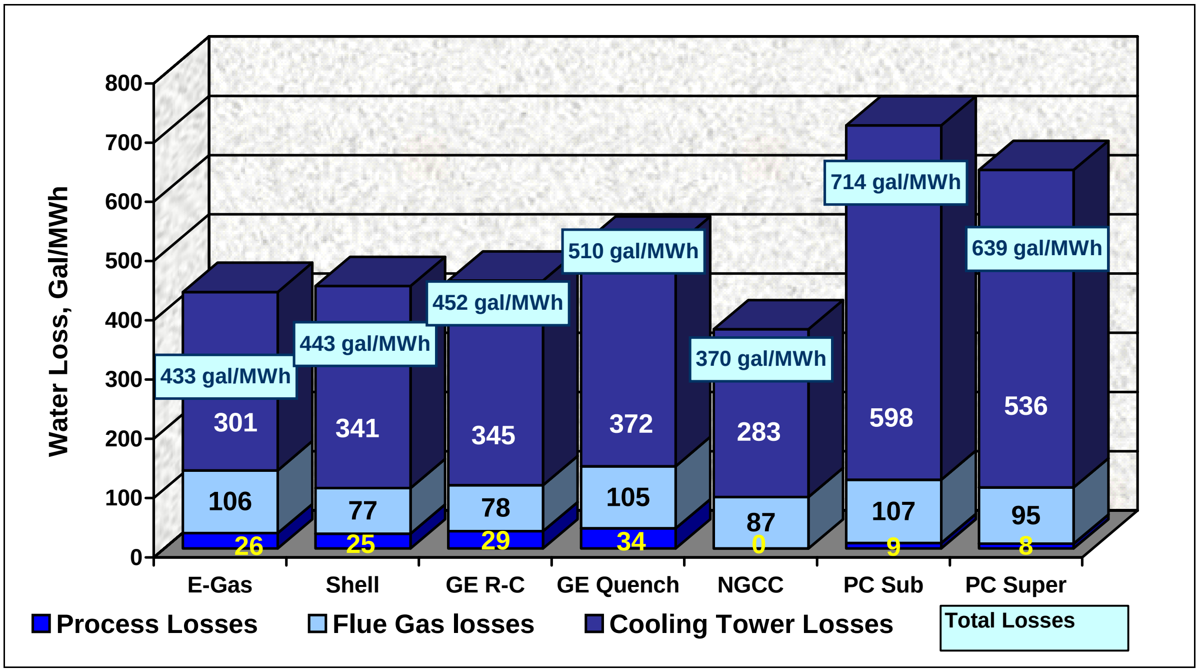
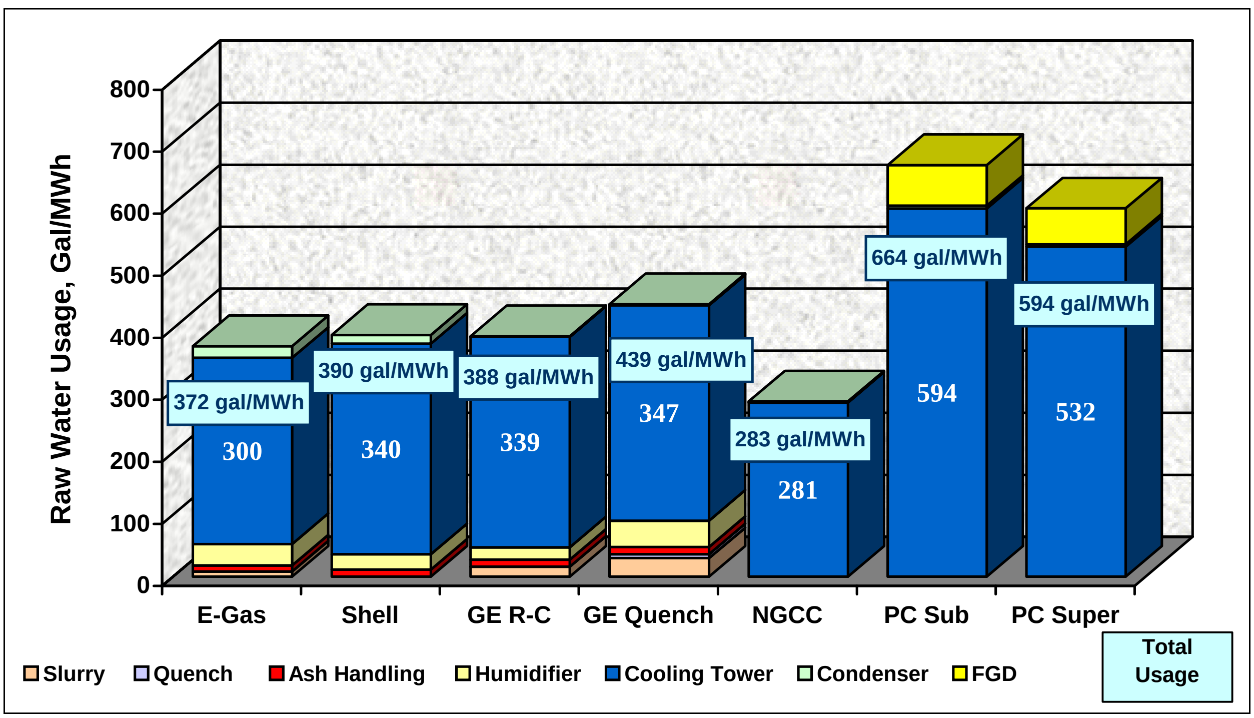


Figure ES-3
Comparison of Raw Water Usage for Various Fossil Plants, gallons per MWh



1. INTRODUCTION

Estimates have been previously made of water usage or water loss for conceptual power plant configurations and have been used as the basis for comparisons of the water impacts of technology options. These previous estimates have been made using available flow sheet data that have generally not been complete, and as a result have generated potentially misleading comparisons. It is important that any comparisons be made using data from complete water balances for the flow sheets and that all uses, makeup streams, discharges, internal generation and losses be accounted for in the balance and assessment of water streams in order to establish credible conclusions.

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The plants reviewed were as follows:

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1.2 PLANT COMPARISONS

For each of the plants, heat and material balances were prepared on a common basis with emphasis on the water usage and loss. The distinction between usage and loss is defined as follows:

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Water flows, makeup, and points of loss were identified and quantified. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was tracked for each plant and major process area. The cooling tower makeup requirements were separately determined using a consistently applied methodology as described in Section 1.3.3. Assessing the effects of climatological changes on plant performance and the need for oversizing equipment relative to the standard design have not been addressed in this report but could be considered for future studies.

For each of the seven power plants, the following were prepared as deliverables:

- Plant Performance Summary
- Heat and Material Balance
- Emission Performance
- Process Block Flow Diagram
- Water Block Flow Diagram
- Overall Water Balance
- Major Plant Sections Water Balance
- Discussion of Water Loss

1.3 PLANT DESIGN BASIS

The performance and environmental data developed in this report are the result of maintaining a consistent design basis throughout. Common design inputs for site, ambient, and fuel characteristics were developed and are defined in the following subsections.

1.3.1 Plant Site and Ambient Design Conditions

The plant site is assumed to be a mid-United States location consisting of approximately 300 usable acres (not including ash disposal) within 15 miles of a medium-sized metropolitan area, with a well-established infrastructure capable of supporting the required construction work force. The area immediately surrounding the site has a mixture of agricultural and light industrial uses. The site is served by a river of adequate quantity for use as makeup cooling water with minimal pretreatment.

A railroad line suitable for unit coal trains passes within 2-1/2 miles of the site boundary. A well-developed road network serves the site, capable of carrying multiple loads and with overhead restriction of not less than 16 feet (Interstate Standard).

The site is on relatively flat land with a maximum difference in elevation within the site of about 30 feet. The topography of the area surrounding the site is rolling hills, with elevations within 2,000 yards not more than 300 feet above the site elevation.

The site is within Seismic Zone 1, as defined by the Uniform Building Code. Table 1-1 lists the ambient characteristics of this site.

Table 1-1
Site Characteristics

Location	Mid USA
Topography	Level
Elevation	500 feet
Design Air Pressure	14.4 psia
Design Temperature, dry bulb	63°F
Corresponding Relative Humidity	55%
Design Temperature, dry bulb max.	89°F
Design Temperature, wet bulb max.	75°F
Design Temperature, min.	1°F
Transportation	Rail access
Water	On site
Ash Disposal	Off site

1.3.2 Feedstocks

Feedstocks are characterized in the following tables:

Pittsburgh No. 8 coal	See Table 1-2
Natural gas	See Table 1-3
Greer limestone	See Table 1-4

Table 1-2
Base Coal Analysis – Pittsburgh No. 8

Ultimate Analysis			
Constituent	**Air Dry, %**	**Dry, %**	**As Received, %**
Carbon	71.88	73.79	69.36
Hydrogen	4.97	4.81	5.18
Nitrogen	1.26	1.29	1.22
Sulfur	2.99	3.07	2.89
Ash	10.30	10.57	9.94
Oxygen	8.60	6.47	11.41
Total	100.00	100.00	100.00

Proximate Analysis		
	Dry Basis, %	**As Received, %**
Moisture	--	6.00
Ash	10.57	9.94
Volatile Matter	38.20	35.91
Fixed Carbon	51.23	48.15
Total	100.00	100.00
Sulfur	3.07	2.89
Btu Content	13,244	12,450
Moisture and Ash Free (MAF), Btu	14,810	
Ash Analysis, %		
Silica, SiO_2	48.1	
Aluminum Oxide, Al_2O_3	22.3	
Iron Oxide, Fe_2O_3	24.2	
Titanium Dioxide, TiO_2	1.3	
Calcium Oxide, CaO	1.3	
Magnesium Oxide, MgO	0.6	
Sodium Oxide, Na_2O	0.3	
Potassium Oxide, K_2O	1.5	
Sulfur Trioxide, SO_3	0.8	
Phosphorous Pentoxide, P_2O_5	0.1	
Total	100	
Ash Fusion Temperature		
	Reducing Atmosphere, °F	**Oxidizing Atmosphere, °F**
Initial Deformation	2015	2570
Spherical	2135	2614
Hemispherical	2225	2628
Fluid	2450	2685

Table 1-3
Natural Gas Analysis

	Volume, %
CH_4	90
C_2H_6	5
N_2	5
HHV, Btu/scf	1,002
HHV, Btu/lb	21,824

Table 1-4
Greer Limestone Analysis

	Dry Basis, %
Calcium Carbonate, $CaCO_3$	80.40
Magnesium Carbonate, $MgCO_3$	3.50
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

1.3.3 Cooling System Makeup Methodology

All cases in this report are compared based on the cooling system as described in this subsection. Each design case assumes that the waste heat from all plant components is rejected by the closed recirculating water system equipped with evaporative mechanical draft cooling towers. Thus, the cooling system heat duty takes into account heat load not only from the steam turbine condenser, but also from the gasifier, combustion turbine, steam turbine, ASU and other plant auxiliaries.

Heat from the steam turbine condenser is removed by the circulating water system, which takes suction from the circulating water pumps located in the cooling tower basin. Heat from the balance-of-plant equipment is also removed by the cooling water system via the auxiliary cooling water system. In this study it is assumed that the auxiliary heat load is 100 MMBtu/h for all cases. The heated circulating water is then discharged back to the cooling tower where cooling occurs mostly by evaporation. While for a specific plant, the cooling system is optimized to meet project economic and technical design criteria, hypothetical assumptions were made for comparative purposes in this study.

Makeup water is drawn from the plant raw water supply system to account for water losses due to evaporation, cooling tower blowdown, and drift in the cooling system, and water losses related to other plant processes. Water losses due to evaporation are largely dependent upon cooling system heat duty, since about 70% of heat in the cooling tower is rejected by evaporation. The amount of cooling system blowdown, generally a function of the makeup water quality, amounts to one-fourth of the makeup. The makeup water available for most cooling towers in the US will permit two to four cycles of concentrations of dissolved solids in the circulating water. For a specific installation, an economic balance between blowdown and water treatment is typically established in order to obtain the lowest capital costs. Four cycles of concentration are assumed for this study.

Cooling system sizing is based upon wet bulb average maximum temperatures that are exceeded by no more than 2% during the year for the Chicago area. Total water losses (evaporation, blowdown and drift) are calculated as follows: [1]

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses as follows:
  - Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1)

Where cycles of concentration is a measure of water quality, and a value of 4 was chosen for this study. Evaporative and drift losses are combined and reported as evaporative losses in the balance of the report.

Other cooling system assumptions in this study are summarized in Table 1-5:

Table 1-5
Cooling System Assumptions

System type: Closed recirculating system with evaporative mechanical draft cooling towers	
Design dry bulb max. ambient temperature, °F	89
Design wet bulb max. ambient temperature, °F	75
Cooling tower approach, °F	5
Cooling tower range, °F	25
Cold circulating water temperature to condenser, °F	80
Hot circulating water temperature from condenser, °F	105
Circulating water cycles of concentration	4
Cooling tower drift (% of CW flow rate)	0.001%

[1] Cooling Tower Fundamentals, ed. John C. Hensley, 2nd Edition, The Marley Cooling Tower Company, Mission, Kansas, 1985

2. WATER LOSS ANALYSIS OF THE CONOCOPHILLIPS E-GAS IGCC PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

This IGCC plant design is based on the ConocoPhillips Energy Corporation E-GAS™ gasification technology, which utilizes two pressurized entrained-flow E-GAS™ two-stage gasifiers to meet the syngas fuel requirements for two General Electric 7FA combustion turbines.

The power generation technology is based on selection of a gas turbine derived from the General Electric 7FA machine. The plant is configured with two gasifiers including processes to progressively cool and clean the gas, making it suitable for combustion in the gas turbines. The resulting plant produces a net output of 526 MWe at a net efficiency of 39.2 percent on an HHV basis. Performance is based on the properties of Pittsburgh No. 8 coal, described in the plant design basis. Overall performance for the entire plant is summarized in Table 2-1, which includes auxiliary power requirements.

Table 2-1
E-GAS IGCC Plant Performance Summary
100 Percent Load

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	394,000
Steam Turbine	227,900
Total	621,900
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	460
Coal Milling	950
Coal Slurry Pumps	330
Slag Handling and Dewatering	300
Air Separation Unit Auxiliaries	40,500
Oxygen Compressor	10,220
Main Nitrogen Compressor	23,040
Nitrogen Boost Compressor	750
Recycle Gas Blower	760
Syngas Recycle Blower	2,370
HP Boiler Feedwater Pump	3,800
LP Boiler Feedwater Pump	200
Humidification Tower Pump	260
Humidification Makeup Pump	180
Condensate Pump	400
Flash Bottoms Pump	150
Circulating Water Pumps	3,420
Cooling Tower Fans	1,890
Scrubber Pumps	400
Amine Unit Auxiliaries	1,700
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	400
Claus Plant/TGTU Auxiliaries	300
Miscellaneous Balance of Plant	1,000
Transformer Loss	1,510
TOTAL AUXILIARIES, kWe	96,070
Net Power, kWe	525,830
Net Plant Efficiency, % HHV	39.2%
Net Heat Rate, Btu/kWh (HHV)	8,717
CONDENSER COOLING DUTY, 10^6 Btu/h	1,139
CONSUMABLES	
As-Received Coal Feed, lb/h	368,068
Thermal Input, kWt	1,342,028
Gasifier Oxygen (95% pure), lb/h	323,028
Claus Plant Oxygen (95% pure), lb/h	4,819
Water (for slurry), lb/h	156,150

[1] HHV of As-Fed Pittsburgh 6 % Moisture Coal is 12,450 Btu/lb

2.1 HEAT AND MATERIAL BALANCE

The heat and material balance for the IGCC plant is based on the syngas fuel requirements for two General Electric 7FA gas turbines. Ambient operating conditions are indicated in the plant design basis. The pressurized entrained flow E-GAS™ two-stage gasifier uses a coal/water slurry and oxygen to produce a medium heating value fuel gas.

The syngas produced in the gasifier first stage at about 2500°F is quenched to 1900°F by reacting with slurry injected into the second stage. The syngas passes through a fire tube boiler syngas cooler and leaves at 1060°F where it then is used to heat the fuel gas saturation water. High-pressure saturated steam is generated in the syngas cooler and is joined with the main steam supply.

The gas goes through a series of additional gas coolers and cleanup processes including a cyclone, filter, scrubber, COS hydrolysis reactor, and an amine-based AGR plant. Slag captured by the filter and syngas scrubber is recovered in a slag recovery unit. Regeneration gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

This plant utilizes a combined cycle for combustion of the syngas from the gasifier to generate electric power. Syngas humidification along with steam and nitrogen dilution of the syngas aids in minimizing formation of NO_X during combustion in the gas turbine burner section. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (fire tube boiler syngas cooler).

Figure 2-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 2-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 2-1
E-GAS™ Gasifier-Based IGCC Case – Block Flow Diagram

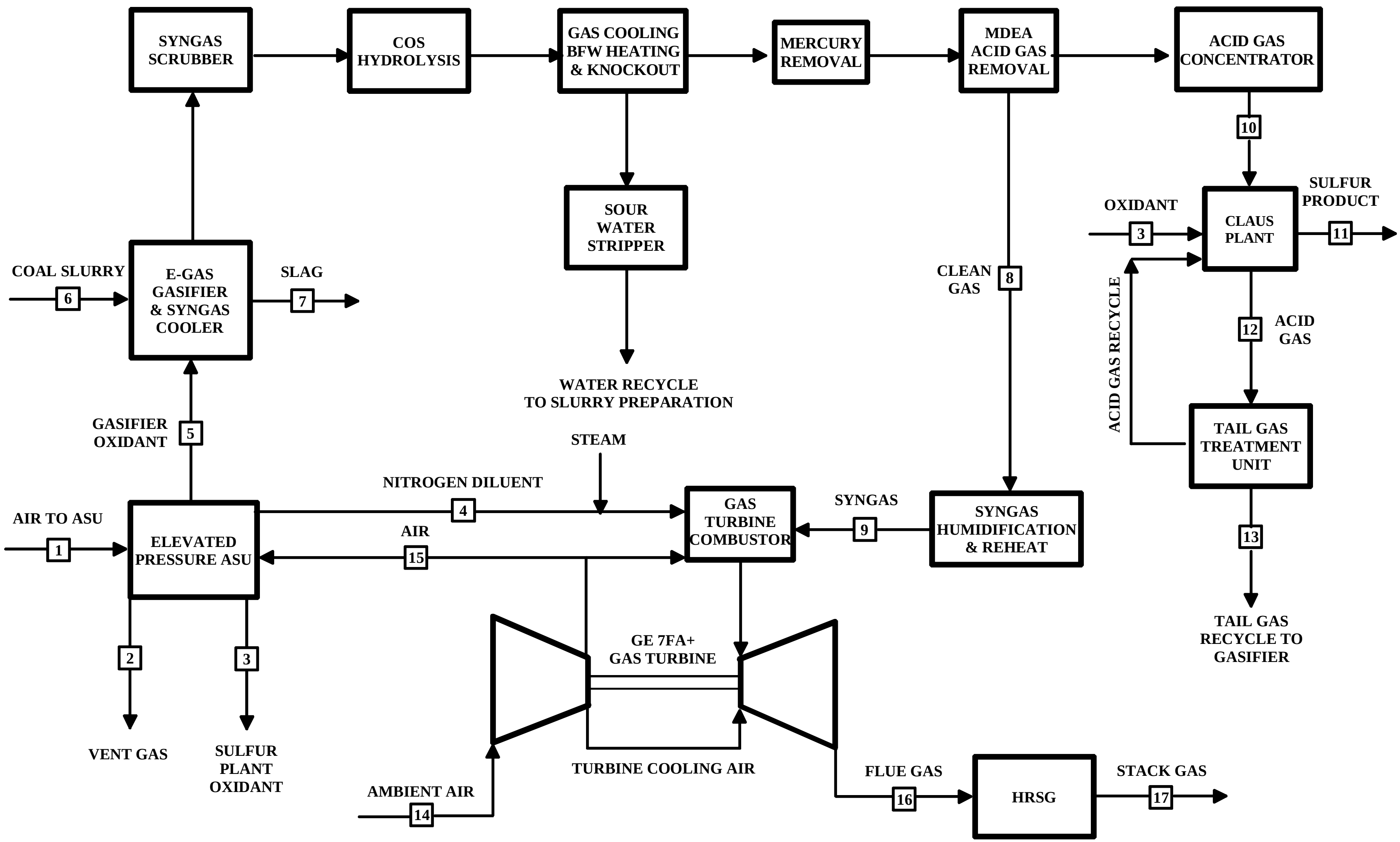


Table 2-2
E-GAS™ Gasifier-Based Dual-Train IGCC Stream Tables (page 1 of 2)

	1	2	3	4	5	6[A]	7	8	9	10
V-L Mole Fraction										
Ar	0.0094	0.0402	0.0360	0.0000	0.0360	0.0000	0.0000	0.0112	0.0091	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0091	0.0074	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5426	0.4418	0.0000
CO_2	0.0003	0.0050	0.0000	0.0000	0.0000	0.0000	0.0000	0.0924	0.0752	0.5120
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3294	0.2682	0.0000
H_2O	0.0108	0.1850	0.0000	0.0000	0.0000	1.0000	0.0000	0.0062	0.1907	0.0623
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4257
N_2	0.7719	0.7694	0.0140	1.0000	0.0140	0.0000	0.0000	0.0092	0.0075	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2076	0.0004	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	28,559	2,725	150	33,714	10,023	8,668	0	32,831	40,316	747
V-L Flowrate (lb/hr)	823,906	72,819	4,819	944,459	323,028	156,150	0	685,753	820,610	28,517
Solids Flowrate (lb/hr)	0	0	0	0	0	368,068	37,850	0	0	0
Temperature (°F)	225	70	90	450	305	59	2,500	123	535	123
Pressure (psia)	190.0	16.4	30.0	295.0	560.0	14.4	500.0	370.8	350.0	30.2
Density (lb/ft^3)	0.746	0.125	0.164	0.847	2.199	62.622	185.286	1.240	0.667	0.186
Molecular Weight	28.849	26.743	32.229	28.013	32.229	18.015	-	20.888	20.354	38.165

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

Table 2-2 (cont'd)
E-GAS™ Gasifier-Based Dual-Train IGCC Stream Tables (page 2 of 2)

	11	12	13	14	15	16	17
V-L Mole Fraction							
Ar	0.0000	0.0048	0.0092	0.0094	0.0094	0.0085	0.0085
CH_4	0.0000	0.0000	0.0184	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0514	0.0004	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.5637	0.8659	0.0003	0.0003	0.0784	0.0784
COS	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0070	0.0101	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.3631	0.0908	0.0108	0.0108	0.0949	0.0949
H_2S	0.0000	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0027	0.0051	0.7719	0.7719	0.7149	0.7149
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.2076	0.2076	0.1033	0.1033
SO_2	0.0000	0.0049	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	41	1,133	584	224,441	18,067	270,427	270,429
V-L Flowrate (lb/hr)	10,600	37,924	23,697	6,475,020	521,220	7,796,990	7,796,990
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0
Temperature (°F)	359	450	120	59	755	1,094	249
Pressure (psia)	23.6	23.5	22.2	14.4	205.1	14.8	14.8
Density (lb/ft^3)	329.126	0.081	0.147	0.075	0.454	0.026	0.056
Molecular Weight	256.528	33.480	40.583	28.849	28.849	28.832	28.832

2.2 EMISSIONS PERFORMANCE

The operation of the combined cycle unit in conjunction with oxygen-blown IGCC technology is projected to result in very low levels of emissions of NO_X, SO_2, and particulate. A salable byproduct is produced in the form of elemental sulfur. A summary of the plant emissions is presented in Table 2-3.

Table 2-3
Air Emissions
IGCC, Oxygen-Blown E-GAS™

	lb/10^6 Btu	tons/year 80% capacity	lb/MWh
SO_2	0.014	221	0.120
NO_X	0.024	386	0.210
Particulates	0.006	98	0.053
CO_2	204	3,269,000	1,774

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the amine-based AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of 30 ppm. This results in a concentration in the flue gas of 3 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas treatment unit removes most of the sulfur from the Claus tail gas, which is recycled to the Claus unit. Tail gas from the tail gas treatment unit is recycled to the gasifier.

NO_X emissions are limited to 5 ppmvd in the flue gas (normalized to 15 percent O_2) by the combined use of syngas dilution (humidification along with steam and nitrogen dilution), and combustion turbine firing based on the DOE/GE development programs to lower NO_X emissions to single digits. Ammonia is removed with process condensate prior to the low-temperature AGR process, which helps lower NO_X levels as well. A selective catalytic reduction (SCR) process is not required.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas scrubber and the gas washing effect of the AGR absorber.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/10^6 Btu), since a similar fuel is used. However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

2.3 WATER BALANCES

Figure 2-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of hydrogen in the syngas. Table 2-4 shows an overall water balance for the entire plant and Table 2-5 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for approximately 70 percent of the water lost followed by 24 percent of the water lost in the flue gas. The slurry fed E-Gas gasification process accounts for 6 percent of the losses.

Table 2-4
E-GAS™ IGCC Overall Water Balance

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	44.2	A	Water Lost in Gasification Shift	97.4
C	Syngas Combustion of H_2 in GT	411.0	6	Ash Handling Blowdown	76.6
22	Combustion air for GT	80.3	7	Water with Slag	26.5
33	Raw Water	3,256	B	Water loss in COS Hydrolysis	0.2
	Moisture in Air to ASU	18.1	24	GT Flue gas	924.4
			31	Sour water blowdown	26.8
			37	Cooling tower blowdown	659.7
			36	Cooling tower evaporation	1,980
				Moisture from ASU Vent	18.1
		3,810			3,810

Table 2-5
E-GAS™ IGCC Water Loss by Function

Gasification losses	gpm	gal/MWh
Water Lost in Gasification Shift	97.4	11.1
Ash Handling Blowdown	76.6	8.7
Water with Slag	26.5	3.0
Water loss in COS Hydrolysis	0.2	0.0
Sour water blowdown	26.8	3.1
Total	227.5	26.0
Flue gas losses		
GT Flue gas	924.4	105.5
Total	924.4	105.5
Cooling water losses		
Cooling tower blowdown	659.7	75.3
Cooling tower evaporation	1,980	225.9
Total	2,640	301.2
Grand Total	3,792	432.7

Figure 2-2
E-GAS™ Gasifier-Based IGCC Case – Block Flow Diagram – Water Flows in Gallons per Minute

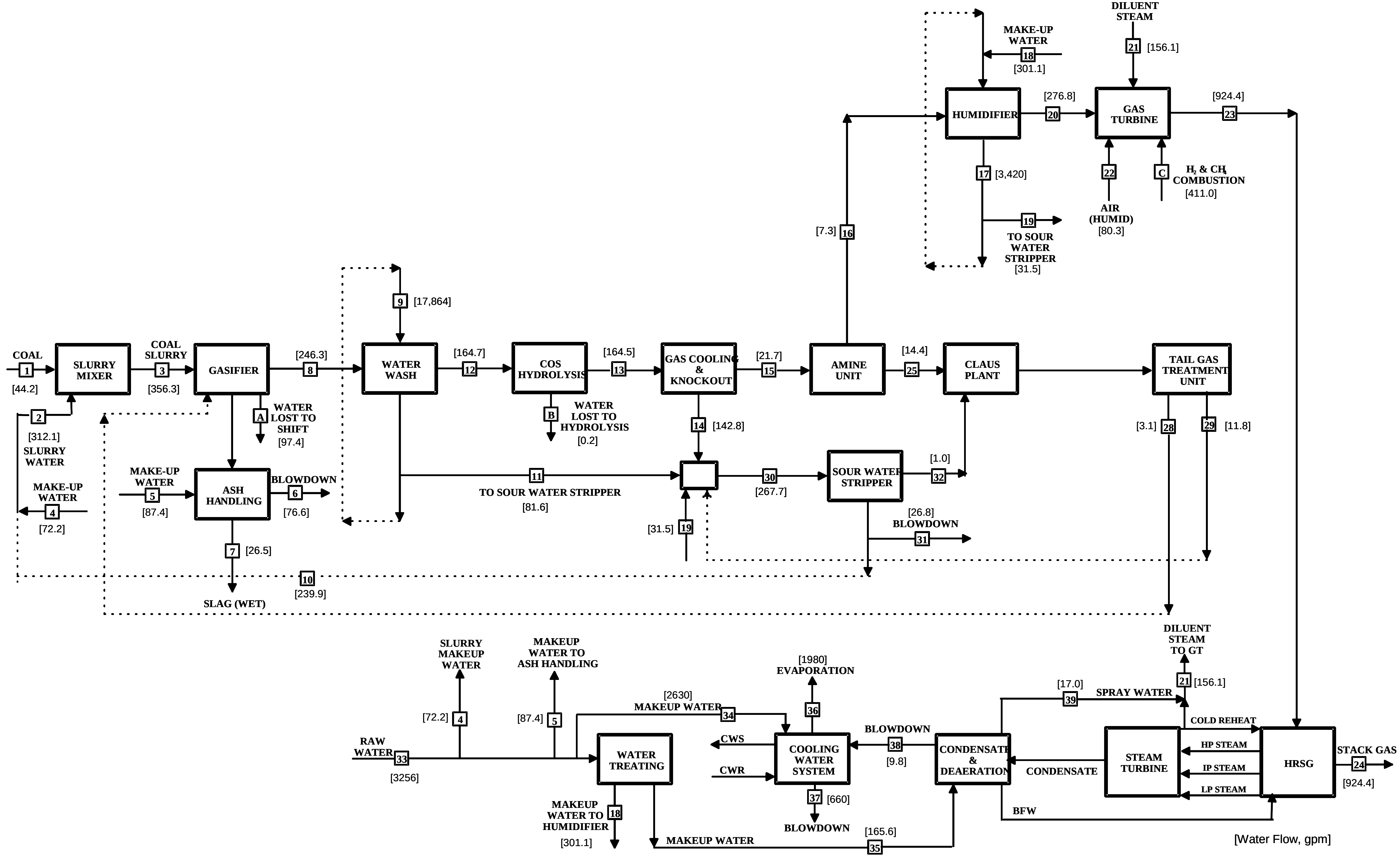


Table 2-6 shows the water balance around the gasification island.

Table 2-6
E-GAS™ IGCC Water Balance Around Gasification Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	44.2	A	Water Lost in Gasification Shift	97.4
4	Slurry Makeup Water	72.2	6	Ash Handling Blowdown	76.6
5	Raw water to ash handling	87.4	7	Water with Slag	26.5
19	From Humidifier Blowdown	31.5	B	Water loss in COS Hydrolysis	0.2
			16	Syngas to Humidification	7.3
			31	Sour water blowdown	26.8
		235			235

Table 2-7 shows the water balance around the power island. A major portion of the water in the flue gas is from the combustion of hydrogen in the syngas produced during gasification, shift and COS hydrolysis.

Table 2-7
E-GAS™ IGCC Water Balance Around Power Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
16	Syngas to Humidification	7.3	19	Humidification blowdown	31.5
18	Humidifier makeup water	301.1	23	GT Flue gas	924.4
21	GT Diluent Steam	156.15			
C	Syngas Combustion of H_2 in GT	411.0			
22	Combustion air for GT	80.3			
		956			956

Table 2-8 shows the water balance around the cooling water system. The wet cooling tower accounts for the majority of the water used in this section.

Table 2-8
E-GAS™ IGCC Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
33	Raw Water	3,256	5	Raw water to ash handling	87.4
			21	GT Diluent Steam	156.15
			18	Humidifier makeup water	301.1
			37	Cooling tower blowdown	659.7
			36	Cooling tower evaporation	1,980
			4	Slurry Makeup Water	72.2
		3,256			3,256

2.4 RAW WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 2-9 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 2-9
E-GAS™ IGCC Raw Water Usage

Water In				**Water Usage**			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
33	Raw Water	3,256	371.6	4	Makeup to Slurry System	72.2	8.2
				5	Makeup water to ash handling	87.4	10.0
				18	Makeup to Humidifier	301.1	34.4
				34	Makeup to Cooling Tower	2,630	300.1
				35	Makeup to Condenser	165.6	18.9
		3,256	372			3,256	372

3. WATER LOSS ANALYSIS OF THE GE ENERGY RADIANT-CONVECTIVE IGCC PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

This IGCC plant design is based on the GE Energy technology, which utilizes a pressurized entrained-flow, oxygen-blown gasification process. The plant configuration is based on the radiant/convective gasifier option operating at approximately 815 psia.

The power generation technology is based on selection of two gas turbines derived from the General Electric 7FA machine. The plant is configured with two operating gasifiers including processes to progressively cool and clean the gas, making it suitable for combustion in the gas turbines. The resulting plant produces a net output of 571 MWe at a net efficiency of 39.4 percent on an HHV basis. Performance is based on the properties of Pittsburgh No. 8 coal, described in the plant design basis. Overall performance for the entire plant is summarized in Table 3-1 which includes auxiliary power requirements.

Table 3-1
GE Energy Radiant-Convective IGCC Plant Performance Summary
100 Percent Load

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	394,000
Sweet Gas Expander Power	9,670
Steam Turbine	270,180
Total	673,850
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	520
Coal Milling	1,050
Coal Slurry Pumps	360
Slag Handling and Dewatering	210
Air Separation Unit Auxiliaries	44,200
Oxygen Compressor	15,300
Main Nitrogen Compressor	22,650
Nitrogen Boost Compressor	880
Claus Tail Gas Recycle Compressor	770
HP Boiler Feedwater Pumps	4,200
IP Boiler Feedwater Pumps	100
LP Boiler Feedwater Pumps	30
Humidification Tower Pumps	130
Scrubber Pumps	100
Circulating Water Pumps	3,080
Cooling Tower Fans	1,840
Condensate Pump	280
Selexol Unit Auxiliaries	2,810
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	400
Claus Plant Auxiliaries	200
Miscellaneous Balance of Plant	1,000
Transformer Loss	1,690
TOTAL AUXILIARIES, kWe	102,600
Net Power, kWe	571,250
Net Plant Efficiency, % HHV	39.4%
Net Heat Rate, Btu/kWh (HHV)	8,668
CONDENSER COOLING DUTY, 10^6 Btu/h	1,440
CONSUMABLES	
As-Received Coal Feed, lb/h	397,706
Thermal Input[1], kWt	1,451,124
Gasifier Oxygen (95% pure), lb/h	378,897
Claus Plant Oxygen (95% pure), lb/h	4,926
Water (for slurry), lb/h	182,455

[1] HHV of As-Fed Pittsburgh 6 % Moisture Coal is 12,450 Btu/lb

3.1 HEAT AND MATERIAL BALANCE

The heat and material balance for the IGCC plant is based on General Electric's estimate for the syngas fuel requirements for two 7FA gas turbines. The pressurized entrained-flow gasifier uses a coal/water slurry and oxygen to produce a medium heating value fuel gas.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. Coal slurry is transferred from the slurry storage tank to the gasifier with a high-pressure pump. At the top of the gasifier vessel is located a combination fuel injector through which coal slurry feedstock and oxidant (oxygen) are fed. The coal slurry and the oxygen feeds react in the gasifier at about 815 psia at a high temperature (in excess of 2500°F) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a radiant cooler where the syngas is cooled and the ash solidifies. Raw syngas then flows to a convective cooler and into a syngas scrubber for removal of entrained solids.

The gas goes through a series of gas coolers and cleanup processes including a COS hydrolysis reactor, a carbon bed mercury removal system, and an AGR plant. Slag captured by the syngas scrubber is recovered in a slag recovery unit. Regeneration gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

This plant utilizes a combined cycle for combustion of the syngas from the gasifier to generate electric power. Humidification of the syngas and nitrogen dilution aids in minimizing formation of NO_X during combustion in the gas turbine burner section. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process.

Figure 3-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 3-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 3-1
GE Energy Radiant-Convective IGCC Case – Block Flow Diagram

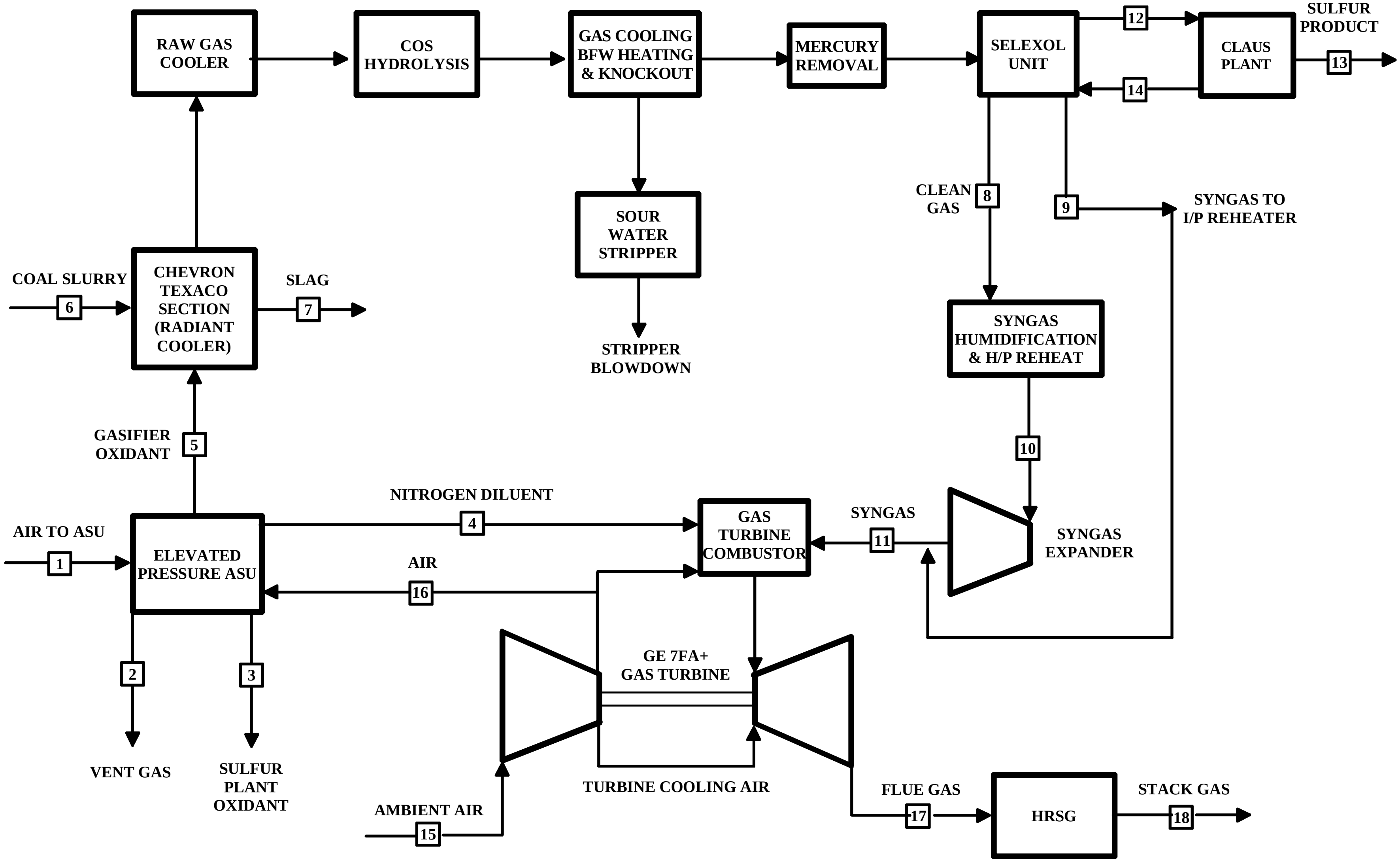


Table 3-2
GE Energy Radiant-Convective IGCC Stream Tables (page 1 of 2)

	1	2	3	4	5	6[A]	7	8	9	10
V-L Mole Fraction										
Ar	0.0094	0.0111	0.0360	0.0000	0.0360	0.0000	0.0000	0.0120	0.0040	0.0105
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0002	0.0006
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4618	0.1140	0.4033
CO_2	0.0003	0.0023	0.0000	0.0000	0.0000	0.0000	0.0000	0.1340	0.4753	0.1170
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3812	0.0606	0.3329
H_2O	0.0104	0.0733	0.0000	0.0000	0.0000	1.0000	0.0000	0.0012	0.0000	0.1277
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000
N_2	0.7722	0.9133	0.0140	1.0000	0.0140	0.0000	0.0000	0.0090	0.3457	0.0079
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	38,516	7,753	153	34,900	11,756	10,128	0	34,505	3,239	39,508
V-L Flowrate (lb/hr)	1,111,350	212,814	4,926	977,663	378,887	182,455	0	702,757	110,414	792,888
Solids Flowrate (lb/hr)	0	0	0	0	0	397,706	45,047	0	0	0
Temperature (°F)	195	57	90	453	280	59	2,500	112	116	520
Pressure (psia)	190.0	16.4	30.0	250.0	1,024.7	14.4	1,050.0	701.7	375.0	688.0
Density (lb/ft^3)	0.780	0.086	0.164	0.715	4.161	62.622	177.478	2.329	2.069	1.313
Molecular Weight	28.854	27.450	32.229	28.013	32.229	18.015	-	20.367	34.086	20.069

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

Table 3-2 (cont'd)
GE Energy Radiant-Convective IGCC Stream Tables (page 2 of 2)

	11	12	13	14	15	16	17	18
V-L Mole Fraction								
Ar	0.0100	0.0000	0.0000	0.0116	0.0094	0.0094	0.0088	0.0088
CH_4	0.0006	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.3814	0.0000	0.0000	0.1409	0.0000	0.0000	0.0000	0.0000
CO_2	0.1441	0.2938	0.0000	0.3411	0.0003	0.0003	0.0832	0.0832
COS	0.0000	0.0005	0.0000	0.0008	0.0000	0.0000	0.0000	0.0000
H_2	0.3123	0.0000	0.0000	0.0852	0.0000	0.0000	0.0000	0.0000
H_2O	0.1180	0.0262	0.0000	0.0041	0.0104	0.0104	0.0760	0.0760
H_2S	0.0000	0.4549	0.0000	0.0117	0.0000	0.0000	0.0000	0.0000
N_2	0.0335	0.2245	0.0000	0.4044	0.7722	0.7722	0.7273	0.7273
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.1047	0.1047
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	42,747	784	44	477	224,404	16,044	271,179	271,175
V-L Flowrate (lb/hr)	903,302	27,614	11,293	15,019	6,475,020	462,940	7,893,050	7,893,050
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0
Temperature (°F)	535	120	353	120	59	724	1,080	237
Pressure (psia)	370.0	30.0	23.6	369.5	14.7	225.6	14.8	14.8
Density (lb/ft^3)	0.732	0.170	329.568	1.868	0.076	0.512	0.026	0.058
Molecular Weight	21.131	35.233	256.528	31.455	28.854	28.854	29.106	29.107

3.2 EMISSIONS PERFORMANCE

The operation of the combined cycle unit in conjunction with oxygen-blown GE Energy IGCC technology is projected to result in very low levels of emissions of NO_X, SO_2, and particulate. A salable byproduct is produced in the form of elemental sulfur. A summary of the plant emissions is presented in Table 3-3.

Table 3-3
Airborne Emissions
IGCC, Oxygen-Blown GE Energy Radiant-Convective

	lb/10^6 Btu	tons/year 80% capacity	lb/MWh
SO_2	0.007	116	0.058
NO_X	0.022	384	0.192
Particulates	0.006	98	0.049
CO_2	200	3,478,000	1,738

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of 15 ppm. This results in a concentration in the flue gas of less than 2 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus tail gas, after hydrogenation, is recycled back to the AGR unit.

NO_X emissions are limited to 5 ppmvd in the flue gas (normalized to 15 percent O_2) by the combined use of syngas dilution (humidification along with nitrogen), and combustion turbine firing based on the DOE/GE development programs to lower NO_X emissions to single digits. Ammonia is removed with process condensate prior to the low-temperature AGR process, which helps lower NO_X levels as well. A selective catalytic reduction (SCR) process is not required.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas scrubber and the gas-washing effect of the AGR absorber.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/10^6 Btu), since a similar fuel is used. However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

3.3 WATER BALANCES

Figure 3-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of hydrogen in the syngas. Table 3-4 shows an overall water balance for the entire plant and Table 3-5 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for over 76 percent of the water lost followed by 17 percent of the water lost in the flue gas. The slurry fed GE Energy gasification process accounts for approximately 6 percent of the losses.

Table 3-4
GE Energy Radiant-Convective IGCC Overall Water Balance

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	47.7	A	Water Lost in Gasification Shift	159.2
C	Syngas Combustion of H_2 in GT	482.7	6	Ash Handling Blowdown	79.9
22	Combustion air for GT	78.1	7	Water with Slag	31.5
33	Raw Water	3,691	B	Water loss in COS Hydrolysis	0.3
	Moisture in Air to ASU	20.5	24	GT Flue gas	742.5
			27	Water Treatment Effluent	4.7
			37	Cooling tower blowdown	820.0
			36	Cooling tower evaporation	2,461
				Moisture in ASU Vent	20.5
		4,320			4,320

Table 3-5
GE Energy Radiant-Convective IGCC Water Loss by Function

Gasification losses	gpm	gal/MWh
Water Lost in Gasification Shift	159.2	16.7
Ash Handling Blowdown	79.9	8.4
Water with Slag	31.5	3.3
Water loss in COS Hydrolysis	0.2	0.0
Water Treatment Effluent	4.7	0.5
Total	275.6	28.9
Flue gas losses		
GT Flue gas	742.5	78.0
Total	742.5	78.0
Cooling water losses		
Cooling tower blowdown	820.0	86.1
Cooling tower evaporation	2,461	258.5
Total	3,281	344.6
Grand Total	4,299	451.6

Figure 3-2
GE Energy Radiant-Convective IGCC Case – Block Flow Diagram – Water Flows in Gallons per Minute

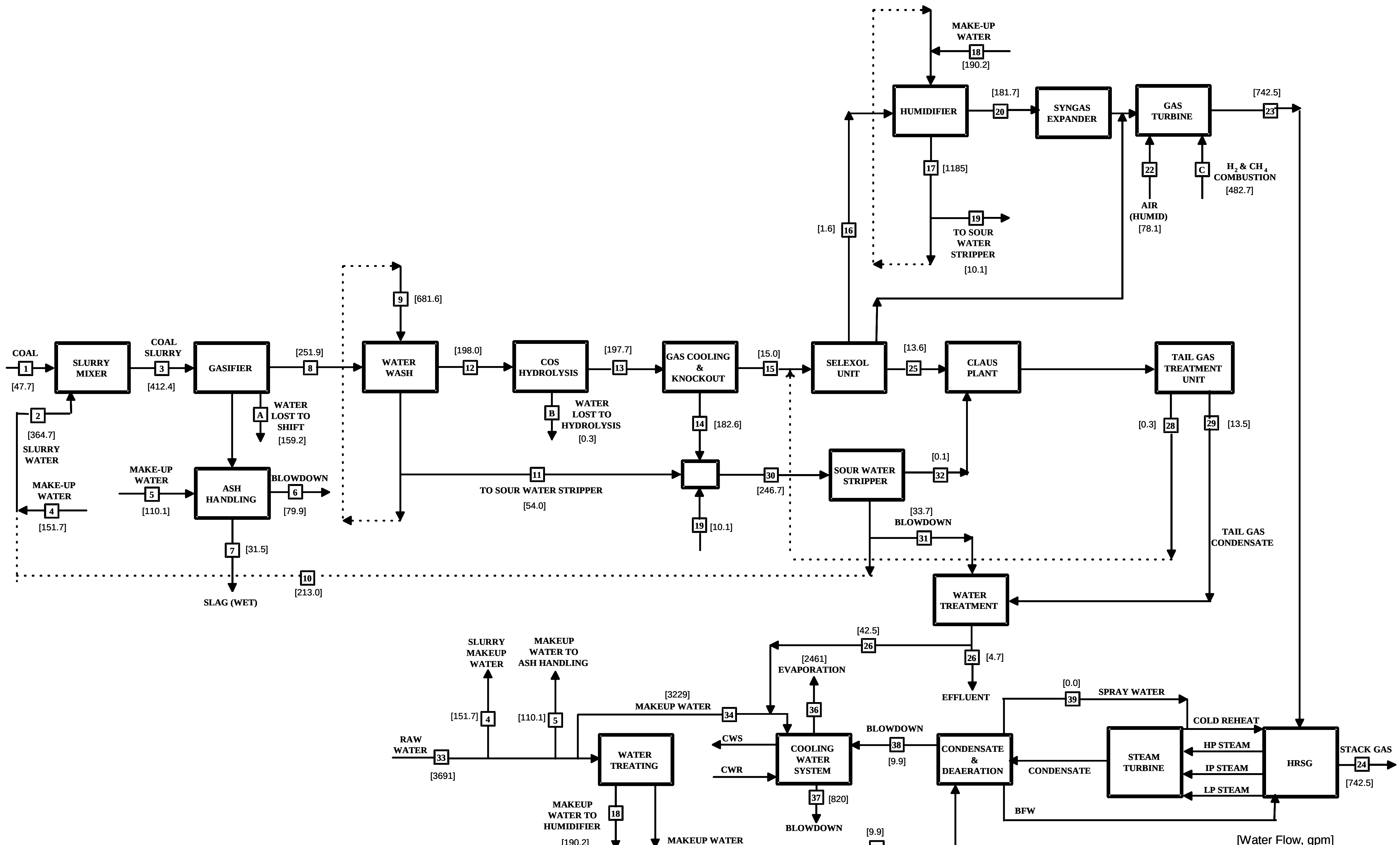


Table 3-6 shows the water balance around the gasification island.

Table 3-6
GE Energy Radiant-Convective IGCC Water Balance Around Gasification Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	47.7	A	Water Lost in Gasification Shift	159.2
4	Slurry Makeup Water	151.7	6	Ash Handling Blowdown	79.9
5	Raw water to ash handling	110.1	7	Water with Slag	31.5
			B	Water loss in COS Hydrolysis	0.3
			16	Syngas to Humidification	1.53
			31	Sour water blowdown	23.7
			29	Tail Gas Condensate	13.5
		310			310

Table 3-7 shows the water balance around the power island. A major portion of the water in the flue gas is from the combustion of hydrogen in the syngas produced during gasification, shift and COS hydrolysis.

Table 3-7
GE Energy Radiant-Convective IGCC Water Balance Around Power Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
16	Syngas to Humidification	1.5	19	Humidification blowdown	10.1
18	Humidifier makeup water	190.2	23	GT Flue gas	742.5
21	GT Diluent Steam	0			
C	Syngas Combustion of H_2 in GT	482.7			
22	Combustion air for GT	78.1			
		753			753

Table 3-8 shows the water balance around the cooling water system. The wet cooling tower accounts for the majority of the water used in this section.

Table 3-8
GE Energy Radiant-Convective IGCC Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
33	Raw Water	3,691	5	Raw water to ash handling	110.1
26	From Waste Water treatment	42.5	21	GT Diluent Steam	0
			18	Humidifier makeup water	190.2
			37	Cooling tower blowdown	820.0
			36	Cooling tower evaporation	2,461
			4	Slurry Makeup Water	151.7
		3,733			3,733

3.4 RAW WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 3-9 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 3-9
GE Energy Radiant-Convective IGCC Raw Water Usage

Water In				Water Usage			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
33	Raw Water	3,691	387.6	4	Makeup to Slurry System	151.7	15.9
				5	Makeup water to ash handling	110.1	11.6
				18	Makeup to Humidifier	190.2	20.0
				34	Makeup to Cooling Tower	3,229	339.1
				35	Makeup to Condenser	9.9	1.0
		3,691	387.6			3,691	387.6

4. WATER LOSS ANALYSIS OF THE GE ENERGY QUENCH IGCC PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

This IGCC plant design is based on the GE Energy technology, which utilizes a pressurized entrained-flow, oxygen-blown gasification process. The plant configuration is based on the quench gasifier option operating at approximately 965 psia.

The power generation technology is based on selection of two gas turbines derived from the General Electric 7FA machine. The plant is configured with two operating gasifiers including processes to progressively cool and clean the gas, making it suitable for combustion in the gas turbines. The resulting plant produces a net output of 522 MWe at a net efficiency of 35.4 percent on an HHV basis. Performance is based on the properties of Pittsburgh No. 8 coal, described in the plant design basis. Overall performance for the entire plant is summarized in Table 4-1, which includes auxiliary power requirements.

Table 4-1
GE Energy Quench IGCC Plant Performance Summary
100 Percent Load

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	394,000
Sweet Gas Expander Power	13,570
Steam Turbine	223,090
Total	630,660
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	520
Coal Milling	1,070
Coal Slurry Pumps	370
Slag Handling and Dewatering	290
Air Separation Unit Auxiliaries	53,120
Oxygen Compressor	15,530
Main Nitrogen Compressor	18,620
Nitrogen Boost Compressor	900
Claus Tail Gas Recycle Compressor	2,030
HP Boiler Feedwater Pumps	2,750
IP Boiler Feedwater Pumps	200
LP Boiler Feedwater Pumps	650
Scrubber Pumps	100
Circulating Water Pumps	3,250
Cooling Tower Fans	1,950
Condensate Pump	310
Selexol Unit Auxiliaries	2,720
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	400
Claus Plant Auxiliaries	200
Miscellaneous Balance of Plant	1,000
Transformer Loss	1,600
TOTAL AUXILIARIES, kWe	108,380
Net Power, kWe	522,280
Net Plant Efficiency, % HHV	35.5%
Net Heat Rate, Btu/kWh (HHV)	9,625
CONDENSER COOLING DUTY, 10^6 Btu/h	1,419
CONSUMABLES	
As-Received Coal Feed, lb/h	403,754
Thermal Input[1], kWt	1,473,192
Gasifier Oxygen (95% pure), lb/h	384,649
Claus Plant Oxygen (95% pure), lb/h	8,524
Water (for slurry), lb/h	185,230

[1] HHV of As-Fed Pittsburgh 6 % Moisture Coal is 12,450 Btu/lb

4.1 HEAT AND MATERIAL BALANCE

The heat and material balance for the IGCC plant is based on General Electric's estimate for the syngas fuel requirements for two 7FA gas turbines. The pressurized entrained-flow gasifier uses a coal/water slurry and oxygen to produce a medium heating value fuel gas.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. Coal slurry is transferred from the slurry storage tank to the gasifier with a high-pressure pump. At the top of the gasifier vessel is located a combination fuel injector through which coal slurry feedstock and oxidant (oxygen) are fed. The coal slurry and the oxygen feeds react in the gasifier at about 965 psia at a high temperature (in excess of 2500°F) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a water-filled quench chamber where the syngas is cooled and the ash solidifies. Raw syngas then flows to the syngas scrubber for removal of entrained solids.

The gas goes through a series of gas coolers and cleanup processes including a COS hydrolysis reactor, a carbon bed mercury removal system, and an AGR plant. Slag captured by the syngas scrubber is recovered in a slag recovery unit. Regeneration gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

This plant utilizes a combined cycle for combustion of the syngas from the gasifier to generate electric power. Humidification of the syngas and nitrogen dilution aids in minimizing formation of NO_X during combustion in the gas turbine burner section. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process.

Figure 4-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 4-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 4-1
GE Energy Quench IGCC Case – Block Flow Diagram

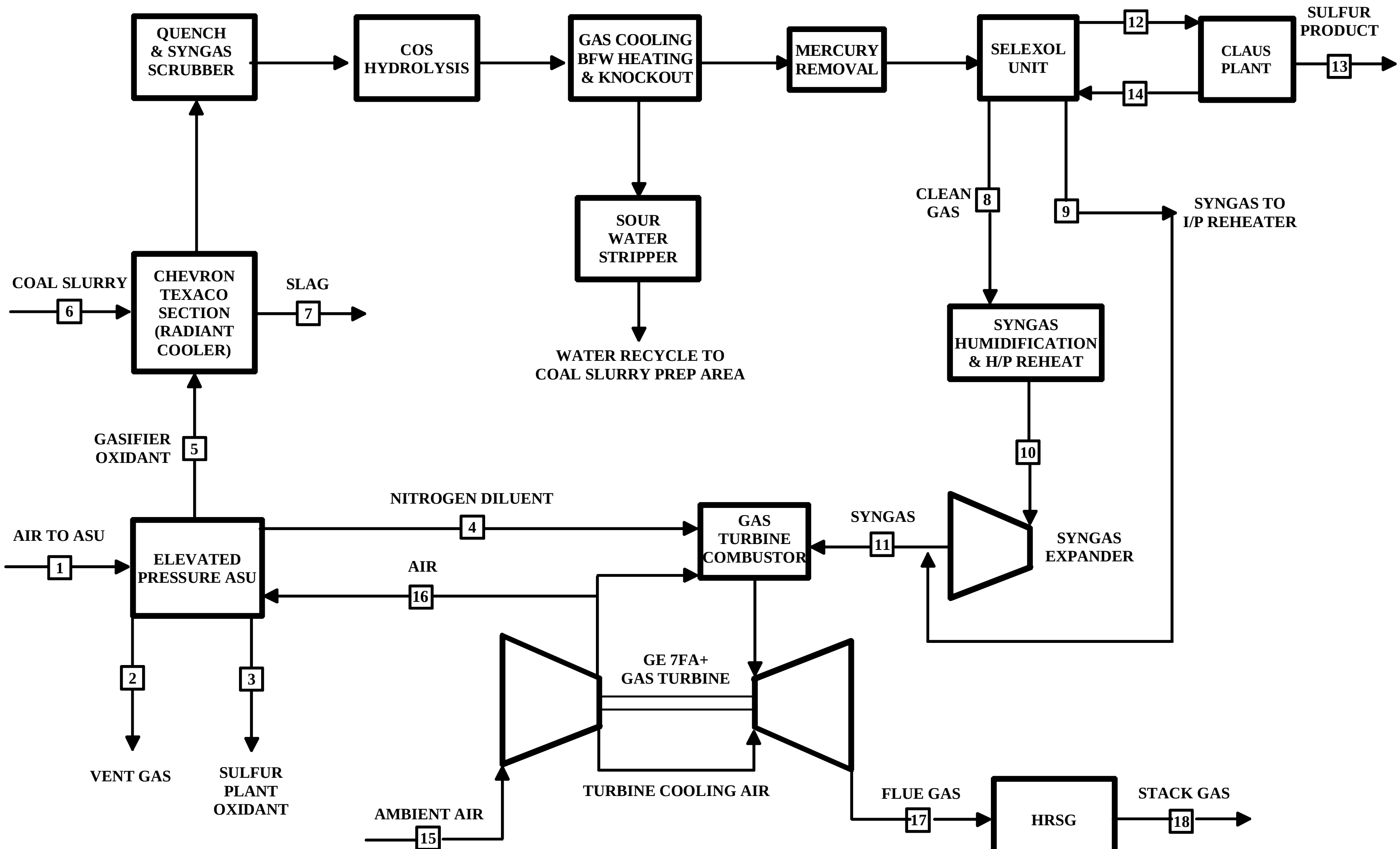


Table 4-2
GE Energy Quench IGCC Stream Tables (page 1 of 2)

	1	2	3	4	5	6[A]	7	8	9	10
V-L Mole Fraction										
Ar	0.0094	0.0072	0.0360	0.0000	0.0360	0.0000	0.0000	0.0121	0.0065	0.0095
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0031	0.0008	0.0024
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4519	0.1673	0.3539
CO_2	0.0003	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.1356	0.4867	0.1062
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3881	0.0509	0.3040
H_2O	0.0104	0.0438	0.0000	0.0000	0.0000	1.0000	0.0000	0.0011	0.0000	0.2175
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000
N_2	0.7722	0.9476	0.0140	1.0000	0.0140	0.0000	0.0000	0.0082	0.2878	0.0064
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	38,252	13,285	264	30,405	11,935	10,282	0	34,187	4,051	43,645
V-L Flowrate (lb/hr)	1,103,740	367,770	8,524	851,741	384,649	185,230	0	690,124	139,948	860,514
Solids Flowrate (lb/hr)	0	0	0	0	0	403,754	45,732	0	0	0
Temperature (°F)	195	56	90	440	280	59	430	112	116	520
Pressure (psia)	190.0	16.4	30.0	250.0	1,024.7	14.4	962.7	848.0	375.0	825.0
Density (lb/ft^3)	0.780	0.085	0.164	0.725	4.161	62.622	177.478	2.789	2.097	1.547
Molecular Weight	28.854	27.683	32.229	28.013	32.229	18.015	-	20.187	34.543	19.716

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

Table 4-2 (cont'd)
GE Energy Quench IGCC Stream Tables (page 2 of 2)

	11	12	13	14	15	16	17	18
V-L Mole Fraction								
Ar	0.0092	0.0000	0.0000	0.0138	0.0094	0.0094	0.0088	0.0089
CH_4	0.0023	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.3381	0.0001	0.0000	0.2808	0.0000	0.0000	0.0000	0.0000
CO_2	0.1385	0.3600	0.0000	0.4777	0.0003	0.0003	0.0848	0.0848
COS	0.0000	0.0008	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000
H_2	0.2825	0.0000	0.0000	0.0360	0.0000	0.0000	0.0000	0.0000
H_2O	0.1991	0.0261	0.0000	0.0040	0.0104	0.0104	0.0938	0.0938
H_2S	0.0000	0.3894	0.0000	0.0073	0.0000	0.0000	0.0000	0.0000
N_2	0.0303	0.2237	0.0000	0.1800	0.7722	0.7722	0.7091	0.7091
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.1034	0.1034
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	47,696	819	45	1,371	224,404	17,638	270,066	270,058
V-L Flowrate (lb/hr)	1,000,460	29,415	11,618	47,863	6,475,020	508,940	7,818,280	7,818,280
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0
Temperature (°F)	535	120	346	120	59	724	1,087	250
Pressure (psia)	370.0	30.0	23.6	369.5	14.7	225.6	14.8	14.8
Density (lb/ft^3)	0.727	0.173	330.085	2.073	0.076	0.512	0.026	0.056
Molecular Weight	20.976	35.907	256.528	34.908	28.854	28.854	28.950	28.950

4.2 EMISSIONS PERFORMANCE

The operation of the combined cycle unit in conjunction with oxygen-blown GE Energy IGCC technology is projected to result in very low levels of emissions of NO_X, SO_2, and particulate. A salable byproduct is produced in the form of elemental sulfur. A summary of the plant emissions is presented in Table 4-3.

Table 4-3
Airborne Emissions
IGCC, Oxygen-Blown GE Energy

	lb/10^6 Btu	tons/year 80% capacity	lb/MWh
SO_2	0.007	115	0.063
NO_X	0.022	387	0.213
Particulates	0.006	98	0.053
CO_2	200	3,531,000	1,929

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of 15 ppm. This results in a concentration in the flue gas of less than 2 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus tail gas, after hydrogenation, is recycled back to the AGR unit.

NO_X emissions are limited to 5 ppmvd in the flue gas (normalized to 15 percent O_2) by the combined use of syngas dilution (humidification along with nitrogen), and combustion turbine firing based on the DOE/GE development programs to lower NO_X emissions to single digits. Ammonia is removed with process condensate prior to the low-temperature AGR process, which helps lower NO_X levels as well. A selective catalytic reduction (SCR) process is not required.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas scrubber and the gas-washing effect of the AGR absorber.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/10^6 Btu), since a similar fuel is used. However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

4.3 WATER BALANCES

Figure 4-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of hydrogen in the syngas. Table 4-4 shows an overall water balance for the entire plant and Table 4-5 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for almost 73 percent of the water lost followed by approximately 20 percent of the water lost in the flue gas. The slurry fed GE Energy gasification process accounts for less than 7 percent of the losses.

Table 4-4
GE Energy Quench IGCC Overall Water Balance

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	48.5	A	Water Lost in Gasification Shift	158.0
C	Syngas Combustion of H_2 in GT	493.1	6	Ash Handling Blowdown	81.1
22	Combustion air for GT	77.5	7	Water with Slag	32.0
33	Raw Water	3,824	B	Water loss in COS Hydrolysis	0.5
	Moisture in Air to ASU	21.0	24	GT Flue gas	912.6
			27	Water Treatment Effluent	22.2
			37	Cooling tower blowdown	808.8
			36	Cooling tower evaporation	2,428
				Moisture in ASU Vent	21.0
		4,464			4,464

Table 4-5
GE Energy Quench IGCC Water Loss by Function

Gasification losses	gpm	gal/MWh
Water Lost in Gasification Shift	158.0	18.2
Ash Handling Blowdown	81.1	9.3
Water with Slag	32.0	3.7
Water loss in COS Hydrolysis	0.5	0.1
Water Treatment Effluent	22.2	2.5
Total	293.7	33.7
Flue gas losses		
GT Flue gas	912.6	104.8
Total	912.6	104.8
Cooling water losses		
Cooling tower blowdown	808.8	92.9
Cooling tower evaporation	2,428	278.9
Total	3,236	371.8
Grand Total	4,443	510.4

Figure 4-2
GE Energy Quench IGCC Case – Block Flow Diagram – Water Flows in Gallons per Minute

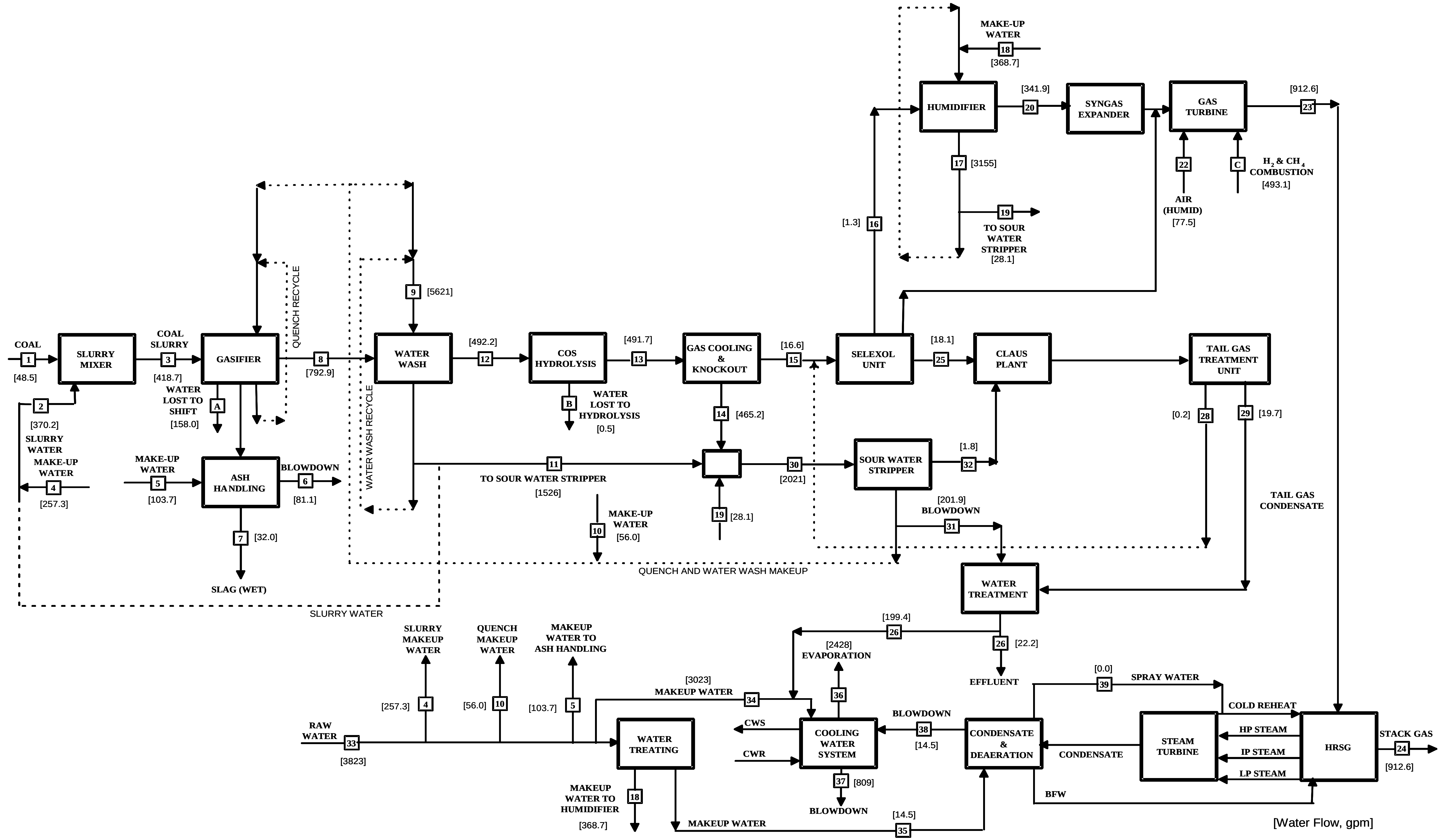


Table 4-6 shows the water balance around the gasification island.

Table 4-6
GE Energy Quench IGCC Water Balance Around Gasification Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	48.5	A	Water Lost in Gasification Shift	158.0
4	Slurry Makeup Water	257.3	6	Ash Handling Blowdown	81.1
5	Raw water to ash handling	103.7	7	Water with Slag	32.0
10	Quench Makeup Water	56.0	B	Water loss in COS Hydrolysis	0.5
19	From Humidifier Blowdown	28.1	16	Syngas to Humidification	1.3
			31	Sour water blowdown	201.9
			21	Syngas to GT	0
			29	Tail Gas Condensate	19.7
		494			494

Table 4-7 shows the water balance around the power island. A major portion of the water in the flue gas is from the combustion of hydrogen in the syngas produced during gasification, shift and COS hydrolysis.

Table 4-7
GE Energy Quench IGCC Water Balance Around Power Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
16	Syngas to Humidification	1.3	19	Humidification blowdown	28.1
18	Humidifier makeup water	368.7	23	GT Flue gas	912.6
21	GT Diluent Steam	0			
C	Syngas Combustion of H_2 in GT	493.1			
22	Combustion air for GT	77.5			
		941			941

Table 4-8 shows the water balance around the cooling water system. The wet cooling tower accounts for the majority of the water used in this section.

Table 4-8
GE Energy Quench IGCC Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
33	Raw Water	3,823	5	Raw water to ash handling	103.7
26	From Water treatment	199.4	21	GT Diluent Steam	0
			18	Humidifier makeup water	368.7
			37	Cooling tower blowdown	808.8
			36	Cooling tower evaporation	2,428
			4	Slurry Makeup Water	257.3
			10	Quench Makeup Water	56.0
		4,022			4,022

4.4 RAW WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 4-9 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 4-9
GE Energy Quench IGCC Raw Water Usage

Water In				**Water Usage**			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
33	Raw Water	3,823	439.2	4	Makeup to Slurry System	257.3	29.6
				5	Makeup water to ash handling	103.7	11.9
				10	Makeup to Quench System	56.6	6.4
				18	Makeup to Humidifier	368.7	42.4
				34	Makeup to Cooling Tower	3,023	347.2
				35	Makeup to Condenser	14.5	1.7
		3,823	439.2			3,823	439.2

5. WATER LOSS ANALYSIS OF THE SHELL IGCC PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

This IGCC plant design is based on the Shell Global Solutions gasification technology, which utilizes a pressurized entrained-flow dry-feed gasifier to meet the syngas fuel requirements for two General Electric 7FA combustion turbines.

The power generation technology is based on selection of a gas turbine derived from the General Electric 7FA machine. The plant is configured with two gasifiers including processes to progressively cool and clean the gas, making it suitable for combustion in the gas turbines. The resulting plant produces a net output of 537 MWe at a net efficiency of 40.1 percent on an HHV basis. Performance is based on the properties of Pittsburgh No. 8 coal, described in the plant design basis. Overall performance for the entire plant is summarized in Table 5-1, which includes auxiliary power requirements.

Table 5-1
Shell IGCC Plant Performance Summary
100 Percent Load

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	394,000
Steam Turbine	239,540
Total	633,540
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	450
Coal Milling	940
Slag Handling	310
Air Separation Unit Auxiliaries	45,990
Oxygen Compressor	10,620
Nitrogen Compressor	23,010
Syngas Recycle Compressor	2,110
Incinerator/Coal Dryer Air Compressor	90
HP Boiler Feedwater Pump	3,200
IP Boiler Feedwater Pump	110
Condensate Pump	250
Circulating Water Pumps	2,690
Cooling Tower Fans	1,640
Scrubber Pumps	300
Sulfinol Unit Auxiliaries	360
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	400
Claus Plant/TGTU Auxiliaries	250
Miscellaneous Balance of Plant	1,000
Transformer Loss	1,550
TOTAL AUXILIARIES, kWe	96,070
Net Power, kWe	537,470
Net Plant Efficiency, % HHV	40.1%
Net Heat Rate, Btu/kWh (HHV)	8,503
CONDENSER COOLING DUTY, 106 Btu/h	1,332
CONSUMABLES	
As-Received Coal Feed, lb/h	366,992
Thermal Input[1], kWt	1,339,057
Gasifier Oxygen (95% pure), lb/h	321,918
Claus Plant Oxygen (95% pure), lb/h	3,824

[1] HHV of as-fed Pittsburgh 6.00% moisture coal is 12,450 Btu/lb

5.1 HEAT AND MATERIAL BALANCE

The heat and material balance for the IGCC plant is based on the syngas fuel requirements for two General Electric 7FA gas turbines. The pressurized entrained flow Shell gasifier uses a dry-coal feed and oxygen to produce a medium heating value fuel gas. The syngas produced in the gasifier at about 2700°F and is quenched to around 1650°F by cooled recycled syngas. The syngas passes through a convective cooler and leaves near 450°F. High-pressure saturated steam is generated in the syngas cooler and is joined with the main steam supply.

The gas goes through a series of additional gas coolers and cleanup processes including a filter, scrubber, COS hydrolysis reactor, and a Sulfinol-M AGR plant. Slag captured by the filter and syngas scrubber is recovered in a slag recovery unit. Regeneration gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

This plant utilizes a combined cycle for combustion of the syngas from the gasifier to generate electric power. Steam and nitrogen addition to the syngas aids in minimizing formation of NO_X during combustion in the gas turbine burner section. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (convective syngas cooler).

Figure 5-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 5-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 5-1
Shell Gasifier-Based IGCC Case – Block Flow Diagram

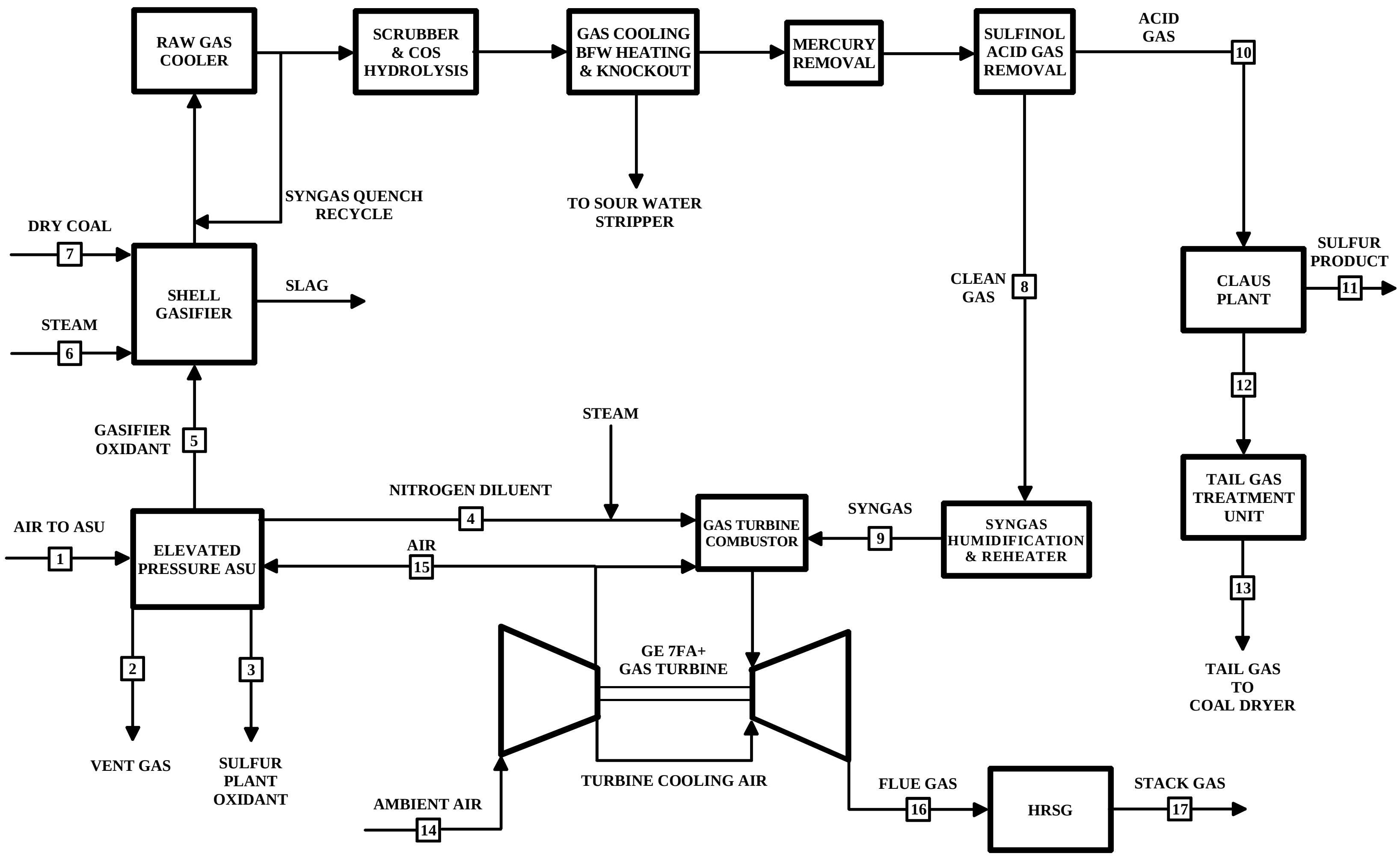


Table 5-2
Shell Gasifier-Based Dual-Train IGCC Stream Tables (page 1 of 2)

	1	2	3	4	5	6	7	8	9
V-L Mole Fraction									
Ar	0.0094	0.0258	0.0360	0.0012	0.0360	0.0000	0.0000	0.0113	0.0095
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6356	0.5355
CO_2	0.0003	0.0060	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0006
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2949	0.2484
H_2O	0.0104	0.1907	0.0000	0.0000	0.0000	1.0000	1.0000	0.0020	0.1592
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7722	0.7775	0.0140	0.9987	0.0140	0.0000	0.0000	0.0553	0.0466
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	36,955	2,528	119	32,075	9,988	1,966	391	31,513	37,405
V-L Flowrate (lb/hr)	1,066,300	67,017	3,824	898,528	321,918	35,411	7,040	645,065	751,216
Solids Flowrate (lb/hr)	0	0	0	0	0	0	344,973	0	0
Temperature (°F)	271	70	90	335	227	450	215	124	400
Pressure (psia)	225.0	16.4	56.4	300.0	650.0	500.0	14.4	357.0	345.0
Density (lb/ft^3)	0.828	0.124	0.308	0.985	2.844	47.395	---	1.167	0.751
Molecular Weight	28.854	24.553	32.184	28.013	32.229	18.015	---	20.470	20.083

Table 5-2 (cont'd)
Shell Gasifier-Based Dual-Train IGCC Stream Tables (page 2 of 2)

	10	11	12	13	14	15	16	17
V-L Mole Fraction								
Ar	0.0003	0.0000	0.0028	0.0037	0.0094	0.0094	0.0088	0.0088
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0103	0.0000	0.1028	0.0128	0.0000	0.0000	0.0000	0.0000
CO_2	0.6559	0.0000	0.5715	0.6545	0.0003	0.0003	0.0746	0.0746
COS	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0052	0.0000	0.0140	0.1377	0.0000	0.0000	0.0000	0.0000
H_2O	0.0054	0.0000	0.2379	0.1009	0.0104	0.0104	0.0695	0.0695
H_2S	0.2518	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0711	0.0000	0.0681	0.0905	0.7722	0.7722	0.7371	0.7371
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.1101	0.1101
SO_2	0.0000	0.0000	0.0011	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	1,297	0	1,725	1,300	223,032	9,350	269,752	269,752
V-L Flowrate (lb/hr)	51,688	0	59,536	44,107	6,435,440	269,800	7,837,930	7,837,930
Solids Flowrate (lb/hr)	0	10,572	0	0	0	0	0	0
Temperature (°F)	124	347	280	123	59	220	1,075	245
Pressure (psia)	60.0	23.6	23.6	14.9	14.4	193.0	14.8	14.7
Density (lb/ft^3)	0.382	---	0.103	0.081	0.075	0.764	0.026	0.056
Molecular Weight	39.847	---	34.508	33.939	28.854	28.854	29.056	29.056

5.2 EMISSIONS PERFORMANCE

The operation of the combined cycle unit in conjunction with oxygen-blown IGCC technology is projected to result in very low levels of emissions of NO_X, SO_2, and particulate. A salable byproduct is produced in the form of elemental sulfur. A summary of the plant emissions is presented in Table 5-3.

Table 5-3
Shell Gasifier Airborne Emissions
IGCC, Oxygen-Blown Shell

	$lb/10^6$ Btu	tons/year 80% capacity	lb/MWh
SO_2	0.007	106	0.056
NO_X	0.023	362	0.192
Particulates	0.006	98	0.052
CO_2	194	3,103,000	1,647

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the Sulfinol-M AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of 15 ppm. This results in a concentration in the flue gas of less than 2 ppm. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas treatment unit removes most of the sulfur from the Claus tail gas, which is recycled to the Claus unit. Vent gas from the tail gas treatment unit is vented to the coal dryer, and the resulting emissions will be less than 2 ppm, meeting air quality standards.

NO_X emissions are limited to 5 ppmvd in the flue gas (normalized to 15 percent O_2) by the combined use of syngas dilution (humidification along with steam and nitrogen addition), and combustion turbine firing based on the DOE/GE development programs to lower NO_X emissions to single digits. Ammonia is removed with process condensate prior to the low-temperature AGR process, which helps lower NO_X levels as well. A selective catalytic reduction (SCR) process is not required.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas scrubber and the gas washing effect of the AGR absorber.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/10^6 Btu), since a similar fuel is used. However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

5.3 WATER BALANCES

Figure 5-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of hydrogen in the syngas. Table 5-4 shows an overall water balance for the entire plant and Table 5-5 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for almost 77 percent of the water lost followed by 17 percent of the water lost in the flue gas. The dry feed Shell gasification process accounts for less than 6 percent of the losses.

Table 5-4
Shell IGCC Overall Water Balance

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	44.0	2	Coal drying moisture	29.9
C	Syngas Combustion of H_2 in GT	331.5	A	Water Lost in Gasification Shift	53.6
22	Combustion air for GT	83.6	6	Ash Handling Blowdown	69.9
27	Combustion air for incinerator	0.7	7	Water with Slag	32.9
33	Raw Water	3,491	B	Water loss in COS Hydrolysis	1.5
D	Syngas combustion of H2 in Incinerator	16.9	24	GT Flue gas	674.6
			28	Incinerator flue gas	13.7
			31	Sour water blowdown	40.5
			37	Cooling tower blowdown	762.5
			36	Cooling tower evaporation	2,289
		3,968			3,968

Table 5-5
Shell IGCC Water Loss by Function

Gasification losses	gpm	gal/MWh
Coal drying moisture	29.9	3.3
Water Lost in Gasification Shift	53.6	6.0
Ash Handling Blowdown	69.9	7.8
Water with Slag	32.9	3.7
Water loss in COS Hydrolysis	1.6	0.2
Sour water blowdown	40.5	4.5
Total	228	25
Flue gas losses		
GT Flue gas	674.6	75.3
Incinerator flue gas	13.7	1.5
Total	688	77
Cooling water losses		
Cooling tower blowdown	762.5	85.1
Cooling tower evaporation	2,289	255.5
Total	3,051	340.6
Grand Total	3,967	443

Figure 5-2
Shell Gasifier-Based IGCC Case – Block Flow Diagram – Water Flows in Gallons per Minute

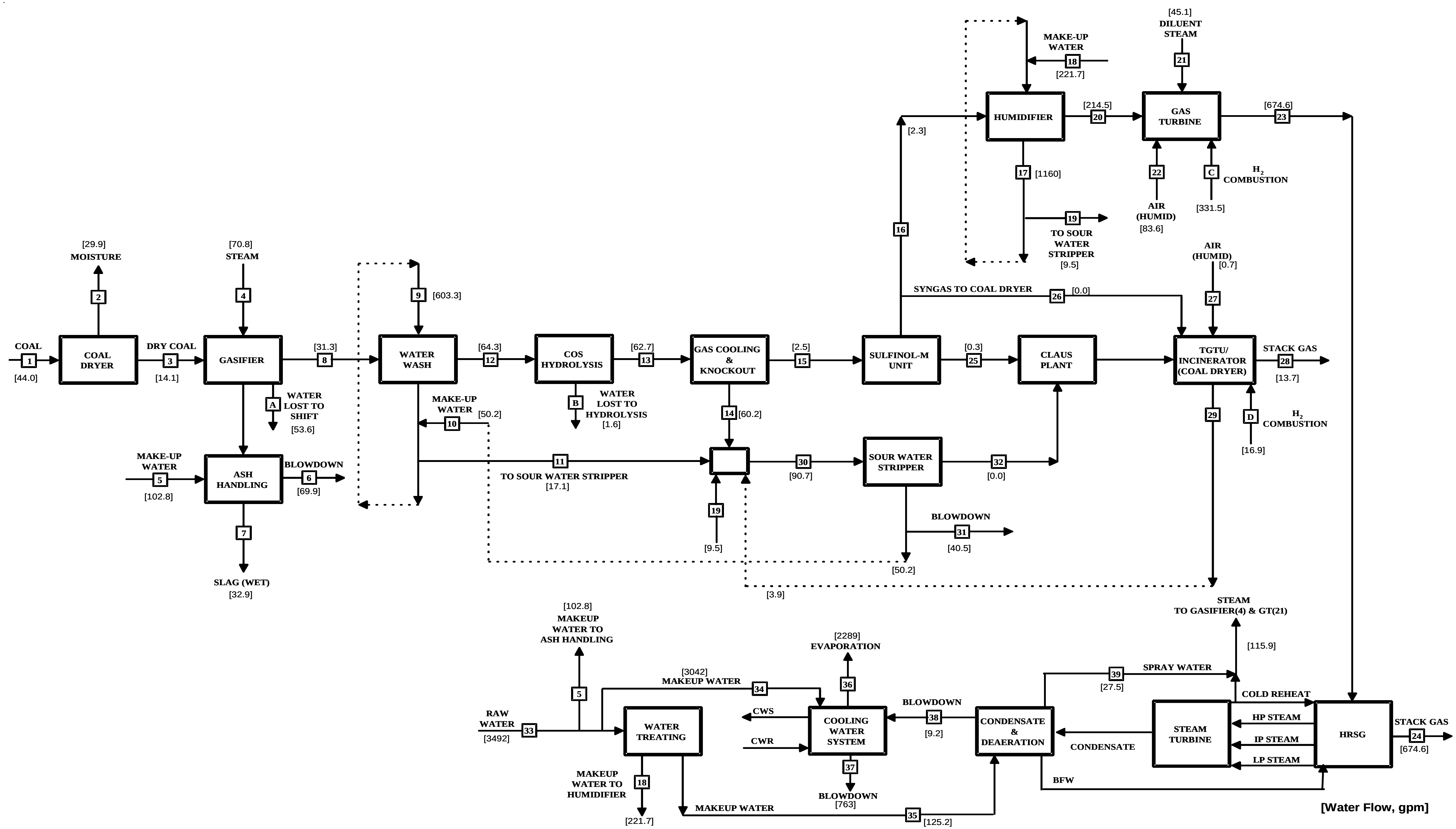


Table 5-6 shows the water balance around the gasification island.

Table 5-6
Shell IGCC Water Balance Around Gasification Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	44.0	2	Coal drying moisture	29.9
4	Steam	70.8	A	Water Lost in Gasification Shift	53.6
5	Raw water to ash handling	102.8	6	Ash Handling Blowdown	69.9
19	From Humidifier Blowdown	9.5	7	Water with Slag	32.9
D	Syngas combustion of H2 in Incinerator	16.9	B	Water loss in COS Hydrolysis	1.6
27	Combustion air for incinerator	0.7	16	Syngas to Humidification	2.3
			27	Incinerator flue gas	13.7
			31	Sour water blowdown	40.5
		245			245

Table 5-7 shows the water balance around the power island. A major portion of the water in the flue gas is from the combustion of hydrogen in the syngas produced during gasification, shift and COS hydrolysis.

Table 5-7
Shell IGCC Water Balance Around Power Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
16	Syngas to Humidification	2.3	19	Humidification blowdown	9.5
18	Humidifier makeup water	221.7	23	GT Flue gas	674.6
21	GT Diluent Steam	45.1			
C	Syngas Combustion of H_2 in GT	331.5			
22	Combustion air for GT	83.6			
		684			684

Table 5-8 shows the water balance around the cooling water system. The wet cooling tower accounts for the majority of the water used in this section.

Table 5-8
Shell IGCC Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
33	Raw Water	3,491	5	Raw water to ash handling	102.8
			4	Steam to Gasifier	70.8
			21	GT Diluent Steam	45.1
			18	Humidifier makeup water	221.7
			37	Cooling tower blowdown	762.5
			36	Cooling tower evaporation	2,289
		3,491			3,491

5.4 RAW WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 5-9 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 5-9
Shell IGCC Raw Water Usage

Water In				Water Usage			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
33	Raw Water	3,492	390	5	Makeup water to ash handling	102.8	11.5
				18	Makeup to Humidifier	221.7	24.7
				34	Makeup to Cooling Tower	3,042	339.6
				35	Makeup to Condenser	125.2	14
		3,492	390			3,492	390

6. WATER LOSS ANALYSIS OF A NATURAL GAS COMBINED CYCLE PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

This design is based on the use of two natural gas-fired combustion turbines, each coupled with a heat recovery steam generator (HRSG) to generate steam for a single steam turbine generator. The plant configuration reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

This rendition of combustion turbine/HRSG technology is based on selection of gas turbines exemplified by the General Electric 7FA machine. This particular machine provides power output, airflow, and exhaust gas temperature that effectively couple with a HRSG to generate steam for the companion steam cycle plant to produce a total net output of approximately 535 MWe, at an efficiency of 55.4 percent (LHV) and 49.9 percent (HHV). For this study, two gas turbines are used in conjunction with one 1800 psig/1050°F/1050°F steam turbine. Overall performance for the entire plant is summarized in Table 6-1, which includes auxiliary power requirements.

Table 6-1
Two 7FA x One NGCC
Plant Performance Summary - 100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	343,400
Steam Turbine Power	191,235
Gross Plant Power (Note 1)	534,635
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	330
High Pressure Boiler Feed Pump	2,240
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	2,810
Cooling Tower Fans	1,600
Transformer Loss	1,650
Total Auxiliary Power Requirement	9,930
NET PLANT POWER, kWe	524,705
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	55.4
Net Heat Rate, Btu/kWh (LHV)	6,165
Net Efficiency, % HHV	49.9
Net Heat Rate, Btu/kWh (HHV)	6,841
CONDENSER COOLING DUTY, 10^6 Btu/h	1,060
CONSUMABLES	
Natural Gas, lb/h (Note 3)	164,488

Note 1 – Loads are presented for two gas turbines, and one steam turbine.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Heating value: 19,666 Btu/lb (LHV), 21,824 Btu/lb (HHV).

6.1 HEAT AND MATERIAL BALANCE

The CT, or gas turbine, generator selected for this application is based on the General Electric 7FA model. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Each CT operates in an open cycle mode. Two 7FAs, each equipped with an individual HRSG, are used to power a single steam turbine in a traditional 2 on 1 arrangement. Pressurized pipeline natural gas is combusted in several parallel dry low- NO_X combustors that use staged combustion to limit NO_X formation.

High-temperature flue gas exiting the CT is conveyed through a HRSG (one for each turbine) to recover the large quantity of thermal energy that remains. The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

The Rankine cycle used in this case is based on a state-of-the-art 1800 psig/1050°F/1050°F single reheat configuration. The steam turbine is a single machine consisting of tandem high-pressure (HP), intermediate-pressure (IP), and double-flow low-pressure (LP) turbine sections connected via a common shaft and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing.

Figure 6-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 6-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 6-1
Natural Gas Combined Cycle Case – Block Flow Diagram

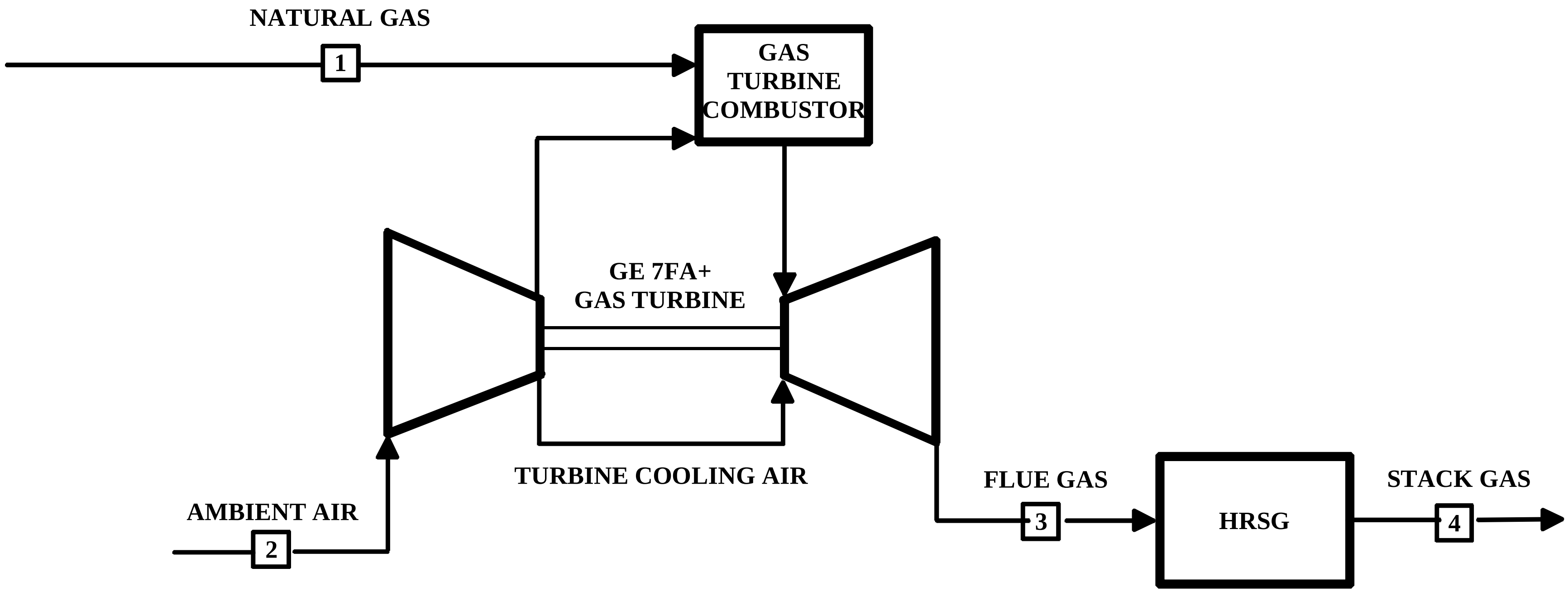


Table 6-2
Natural Gas Combined Cycle Stream Table

	1	2	3	4
V-L Mole Fraction				
Ar	0.0000	0.0094	0.0090	0.0090
C_2H_6	0.0500	0.0000	0.0000	0.0000
CH_4	0.9000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0003	0.0377	0.0377
H_2O	0.0000	0.0108	0.0834	0.0834
N_2	0.0500	0.7719	0.7442	0.7442
O_2	0.0000	0.2076	0.1257	0.1257
Total	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	9,485	243,581	253,303	253,303
V-L Flowrate (lb/hr)	164,488	7,027,200	7,191,690	7,191,690
Temperature (°F)	59	59	300	281
Pressure (psia)	14.7	14.7	14.1	14.1

6.2 EMISSIONS PERFORMANCE

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, is projected to result in very low levels of SO_2, NO_X, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 6-3.

Table 6-3
Airborne Emissions
Two 7FA x One NGCC

	$lb/10^6$ Btu	tons/year 80% capacity	lb/MWh
SO_2	negligible	negligible	negligible
NO_X	0.023	287	0.156
Particulates	0.008	98	0.053
CO_2	117	1,472,000	801

As shown in the table, values of SO_2 emission are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Pipeline natural gas contains minor amounts of reduced sulfur species that produce negligible SO_2 emissions when combusted and diluted with a large amount of air.

As for particulate discharge, when natural gas is properly combusted in a state-of-the-art CT, the amount of solid particulate produced is very small (less than 20 lb/hour for both 7FA machines).

The low level of NO_X production is achieved through use of GE's dry low- NO_X (DLN) combustion system. It is assumed that NO_X emissions are further limited to 5 ppmvd in the flue gas (normalized to 15 percent O_2) by the application of combustion turbine firing based on the DOE/GE development programs to lower NO_X emissions to single digits. A selective catalytic reduction (SCR) process is not required.

CO_2 emissions are about 60% of the amount from coal-burning facilities on an intensive basis ($1b/10^6$ Btu), since natural gas contains about 60% as much carbon as coal on a $1b/10^6$ Btu basis. However, total CO_2 emissions are more than 50% lower than those from a coal plant with this capacity due to the relatively high thermal efficiency.

6.3 WATER BALANCES

Figure 6-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of natural gas. Table 6-4 shows an overall water balance for the entire plant and Table 6-5 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for over 76 percent of the water lost. Losses in the flue gas account for about 24 percent of the total.

Table 6-4
NGCC Overall Water Balance

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
A	Combustion of Natural Gas	666.0	8	Cooling tower evaporation	1,854
3	Combustion air for GT	94.8	9	Cooling tower blowdown	617.6
5	Raw Water	2,472	4	Moisture in flue gas from HRSG	760.9
		3,232			3,232

Table 6-5
NGCC Water Loss by Function

Flue gas losses	gpm	gal/MWh
GT Flue gas	760.8	87.0
Total	760.8	87.0
Cooling water losses		
Cooling tower blowdown	618	70.6
Cooling tower evaporation	1,854	212.0
Total	2,471	282.6
Grand Total	3,232	370

Figure 6-2
NGCC Case – Block Flow Diagram – Water Flows in Gallons per Minute

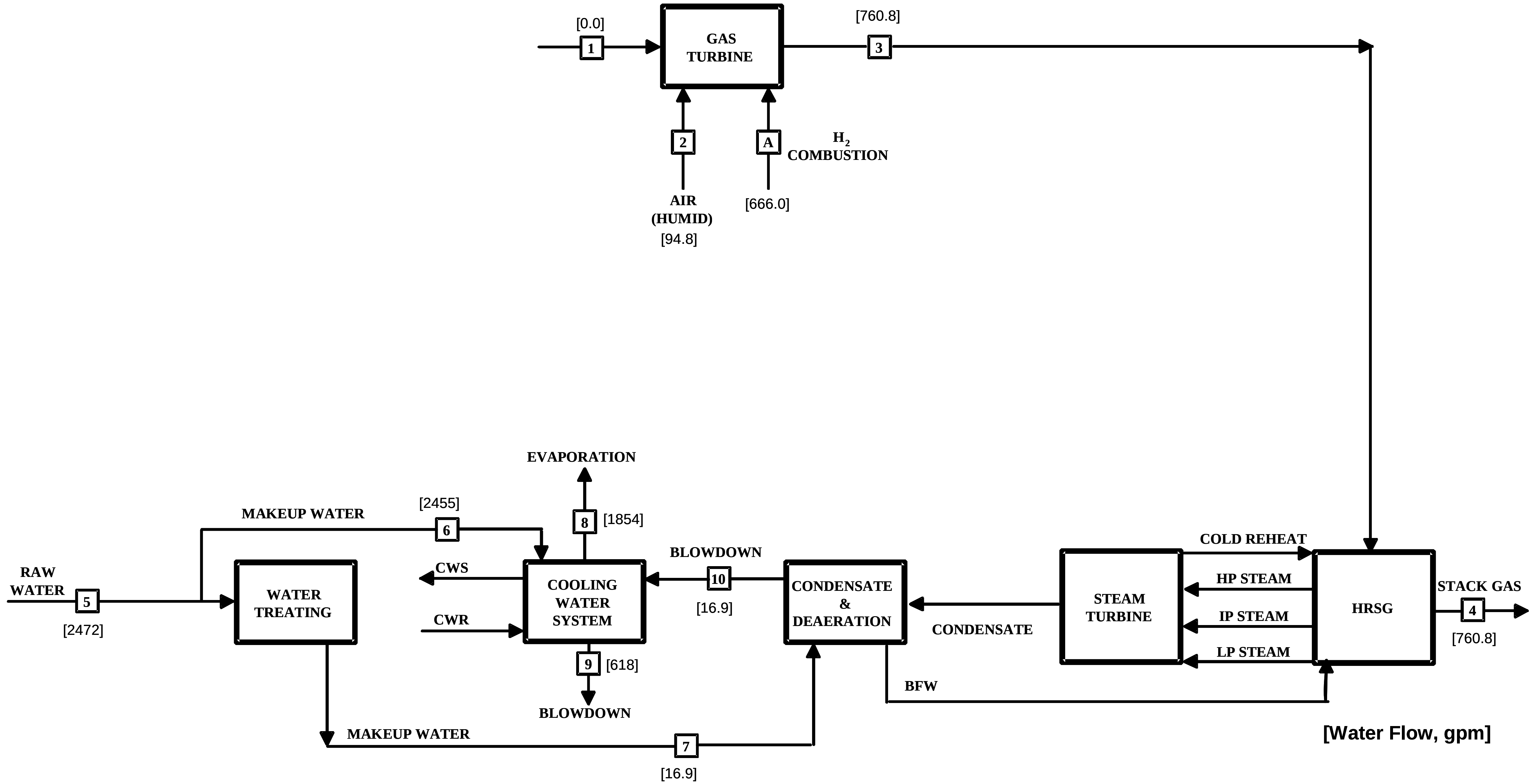


Table 6-6 shows the water balance around the gas turbine island. A major portion of the water in the flue gas is from the combustion of the natural gas.

Table 6-6
NGCC Water Balance Around Gas Turbine Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
A 3	Combustion of Natural Gas Combustion air for GT	666.0 94.8	4	Moisture in flue gas from HRSG	760.9
		761			761

Table 6-7 shows the water balance around the cooling water system. The wet cooling tower accounts for the majority of the water used in this section.

Table 6-7
NGCC Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
5	Raw Water	2,472	8 9	Cooling tower evaporation Cooling tower blowdown	1,854 618
		2,472			2,472

6.4 RAW WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 6-8 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 6-8
NGCC Raw Water Usage

Water In				Water Usage			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
5	Raw Water	2,472	283	6	Makeup to Cooling Tower	2,455	281
				7	Makeup to Condenser	16.9	1.9
		2,472	283			2,472	283

7. WATER LOSS ANALYSIS OF A SUBCRITICAL PULVERIZED COAL PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

The design basis of this pulverized coal plant is a nominal 500 MW subcritical cycle. Support facilities are all encompassing, including rail spur (within the plant fence line), coal handling, (including receiving, crushing, storing, and drying), limestone handling (including receiving, crushing, storing, and feeding), solid waste disposal, flue gas desulfurization, wastewater treatment and equipment necessary for an efficient, available, and completely operable facility. The plant is designed using components suitable for a 30-year life, with provision for periodic maintenance and replacement of critical parts.

The subcritical design uses a 2400 psig/1000°F/1050°F single reheat steam power cycle. The steam generator is a natural circulation, wall-fired, subcritical unit arranged with a water-cooled dry-bottom furnace, superheater, reheater, economizer, and air heater components. There are three rows of six burners per each of two walls.

The resulting plant produces a net output of 521 MWe at a net efficiency of 35.4 percent on an HHV basis. Performance is based on the properties of Pittsburgh No. 8 coal, described in the plant design basis. Overall performance for the entire plant is summarized in Table 7-1, which includes auxiliary power requirements.

Table 7-1
Subcritical PC Boiler Plant Performance Summary
100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,050
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	554,400
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	290
Limestone Handling & Reagent Preparation	200
Pulverizers	2,260
Ash Handling	3,190
Primary Air Fans	1,580
Forced draft Fans	1,250
Induced Draft Fans	6,430
SCR Auxiliaries	300
Seal Air Blowers	50
Precipitators	1,060
FGD Pumps and Agitators	5,540
Condensate Pumps	840
Boiler Feedwater Pumps	(Note 2)
Miscellaneous Balance of Plant (Note 3)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	4,550
Cooling Tower Fans	2,570
Transformer Loss	1,330
TOTAL AUXILIARIES, kWe	33,840
Net Power, kWe	520,560
Net Efficiency, % HHV	35.4%
Net Heat Rate, Btu/kWh (HHV)	9,638
CONDENSER COOLING DUTY, 10^6 Btu/h	2,335
CONSUMABLES	
As-Received Coal Feed, lb/h (Note 1)	402,973
Sorbent, lb/h	41,513

Note 1 - As-received coal heating value: 12,450 Btu/lb (HHV)
Note 2 - Boiler feed pumps are steam turbine driven.
Note 3 - Includes plant control systems, lighting, HVAC, etc.

7.1 HEAT AND MATERIAL BALANCE

The plant uses a 2400 psig/1000°F/1050°F single reheat steam power cycle. The high-pressure (HP) turbine uses steam at 2415 psia and 1000°F. The cold reheat steam flow is reheated to 1050°F before entering the intermediate-pressure (IP) turbine section. Tandem HP, IP, and low-pressure (LP) turbines drive one 3600 rpm hydrogen-cooled generator. The LP turbines consist of two condensing turbine sections.

The feedwater train consists of six closed feedwater heaters (four LP and two HP), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from all of the turbine cylinders.

The net plant power output, after plant auxiliary power requirements are deducted, is nominally 521 MWe. The overall plant efficiency is 35.4 percent.

The major features of this plant include the following:

- Boiler feed pumps are steam turbine driven.
- Turbine configuration is a 3600 rpm tandem compound, four-flow exhaust.
- Plant has six stages of closed feedwater heaters plus a deaerator.

Figure 7-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 7-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 7-1
Subcritical PC Boiler Case – Block Flow Diagram

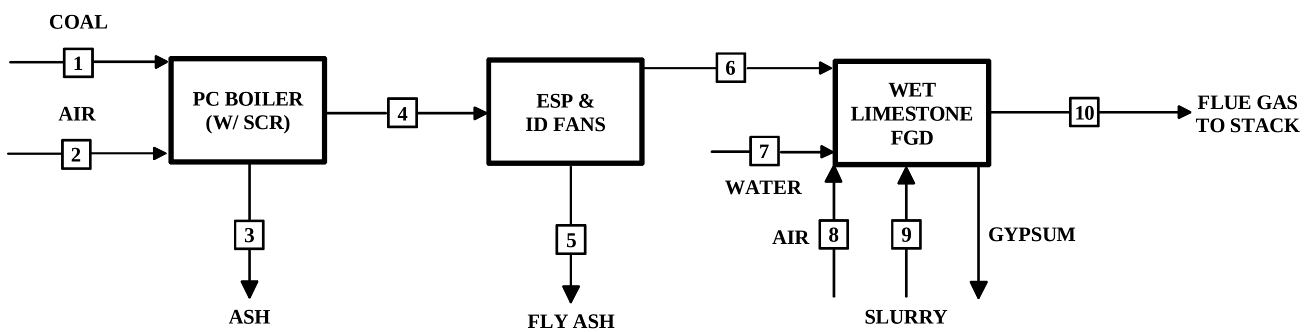


Table 7-2
Subcritical PC Boiler Stream Table

	1	2	3	4	5	6	7	8	9	10
Mole Frac										
Ar	0.0000	0.0094	0.0000	0.0090	0.0000	0.0090	0.0000	0.0094	0.0000	0.0084
CO_2	0.0000	0.0003	0.0000	0.1320	0.0000	0.1320	0.0000	0.0003	0.0000	0.1238
H_2O	0.0000	0.0104	0.0000	0.0690	0.0000	0.0690	1.0000	0.0104	1.0000	0.1350
O_2	0.0000	0.2077	0.0000	0.0445	0.0000	0.0445	0.0000	0.2077	0.0000	0.0414
SO_2	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0000	0.0000	0.0000	0.0001
N_2	0.0000	0.7722	0.0000	0.7433	0.0000	0.7433	0.0000	0.7722	0.0000	0.6913
Total V-L Flow (lb_{mol}/hr)	0	169,157	0	168,160	0	175,959	8,428	1,048	5,377	190,380
Total V-L Flow (lb/hr)	0	4,880,923	0	4,983,410	0	5,242,740	151,831	30,233	96,863	5,504,770
Solids										
Coal (lb/hr)	402,973	0	0	0	0	0	0	0	0	0
Ash (lb/hr)	0	0	8,231	32,925	32,925	0	0	0	0	0
Limestone (lb/hr)	0	0	0	0	0	0	0	0	41,513	0
Temperature (°F)	59	59	300	281	280	343	59	59	100	131
Pressure (psia)	14.7	14.7	14.1	14.1	14.1	17.7	20.0	14.7	20.0	14.7

7.2 EMISSIONS PERFORMANCE

The 1990 CAAA imposed a two-phase capping of SO_2 emissions on a nationwide basis. For a new greenfield plant, the reduction of SO_2 emissions that would be required depends on the availability of SO_2 allowances to the utility, and on local site conditions. In many cases, Prevention of Significant Deterioration (PSD) Regulations will apply, requiring that Best Available Control Technology (BACT) be used. BACT is applied separately for each site, and results in different values for varying sites. In general, the emission limits set by BACT will be significantly lower than NSPS limits. The ranges specified in Table 7-3 will cover most cases. For this study, plant emissions are capped at values shown in Table 7-4.

Table 7-3
Emission Limits Set by BACT

SO_2	92 to 95 percent removal
NO_X	0.1 to 0.45 lb/10^6 Btu
Particulates	0.015 to 0.03 lb/10^6 Btu
Opacity	10 to 20 percent

Source: DOE/FE-0400 MARKET-BASED ADVANCED COAL POWER SYSTEMS FINAL REPORT MAY 1999

Table 7-4
Airborne Emissions
Subcritical PC Boiler

	lb/10^6 Btu	tons/year 80% capacity	lb/MWh
SO_2	0.232	4,081	2.240
NO_X	0.100	1,758	0.964
Particulates	0.024	421	0.231
CO_2	204	3,591,000	1,966

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone forced oxidation FGD system. The nominal overall design basis SO_2 removal rate is set at 95 percent.

The minimization of NO_X production and subsequent emission is achieved by a combination of low- NO_X burners, overfire air staging, and selective catalytic reduction (SCR). The low- NO_X burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NO_X emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern electrostatic precipitator, which provides a particulate removal rate of 99.7 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (lb/MMBtu), since a similar fuel is used.

7.3 WATER BALANCES

Figure 7-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of coal. Table 7-5 shows an overall water balance for the entire plant and Table 7-6 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for nearly 84 percent of the water lost. Losses in the flue gas and FGD system account for 16 percent of the total.

Table 7-5
Subcritical PC Boiler Overall Water Balance

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	48.3	11	PC Boiler flue gas	928.4
2	Coal Combustion of H2 in Boiler	325.5	12	Water with gypsum	80.7
3	Combustion air for PC Boiler	63.4	17	Cooling tower evaporation	3,891
8	Oxidation air for FGD	0.4	18	Cooling tower blowdown	1,297
13	Raw Water	5,759			
		6,197			6,197

Table 7-6
Subcritical PC Boiler Water Loss by Function

FGD losses	gpm	gal/MWh
Water with Gypsum	80.7	9.3
Total	81	9
Flue gas losses		
PC boiler Flue gas	928.4	107.0
Total	928	107
Cooling water losses		
Cooling tower blowdown	1,297	149.5
Cooling tower evaporation	3,891	448.5
Total	5,188	598.0
Grand Total	6,197	714.3

Figure 7-2
Subcritical PC Boiler Case – Block Flow Diagram – Water Flows in Gallons per Minute

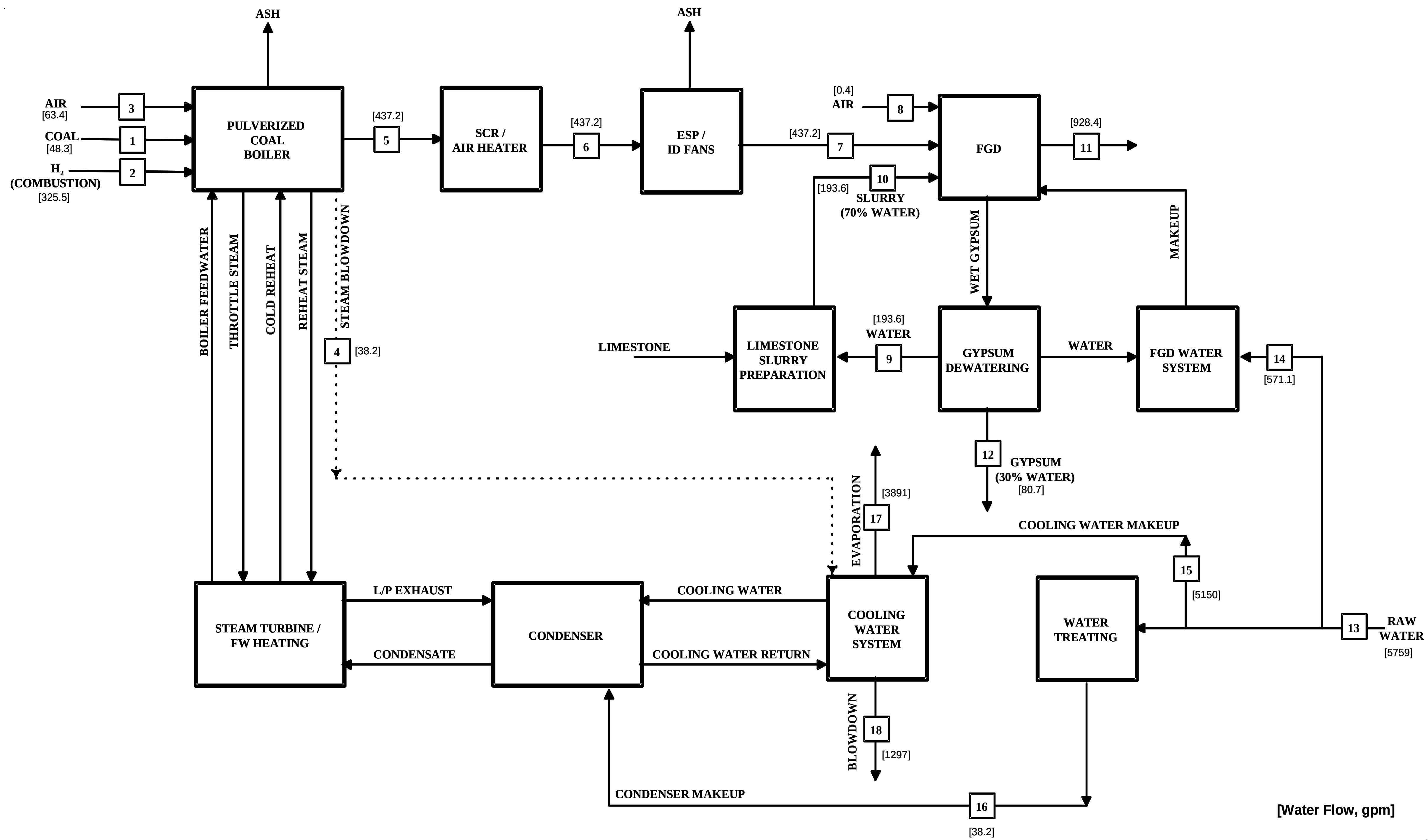


Table 7-7 shows the water balance around the FGD island. Over half of the water that ends up in the flue gas is evaporated from the FGD system.

Table 7-7
Subcritical PC Boiler Water Balance Around FGD Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
7	Moisture in flue gas	437.2	11	Moisture in flue gas	928.4
8	Oxidation air for FGD	0.4	12	Water in Gypsum	80.7
14	Makeup water	571.1			
		1,009			1,009

Table 7-8 shows the water balance around the cooling water system. Over 90 percent of the plant water losses occur here.

Table 7-8
Subcritical PC Boiler Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
4	Steam blowdown	38.2	17	Cooling tower evaporation	3,891
15	Cooling water Makeup	5,150	18	Cooling water blowdown	1,297
		5,188			5,188

7.4 RAW WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 7-9 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 7-9
Subcritical PC Boiler Raw Water Usage

Water In				Water Usage			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
13	Raw Water	5,759	663.8	14	Water to FGD System	571.1	65.8
				15	Makeup to Cooling Tower	5,150	593.6
				16	Makeup to Condenser	38.2	4.4
		5,759	664			5,759	664

8. WATER LOSS ANALYSIS OF A SUPERCRITICAL PULVERIZED COAL PLANT

The study design goal was to track the water flows and usages for all the major sections of the plant. Since essentially all fuel-bound hydrogen ends up as water, hydrogen was also tracked for each plant and major process area. An overall water balance and a water balance for each major plant section was then generated.

The design basis of this pulverized coal plant is a nominal 500 MWe supercritical cycle. Support facilities are all encompassing, including rail spur (within the plant fence line), coal handling, (including receiving, crushing, storing, and drying), limestone handling (including receiving, crushing, storing, and feeding), solid waste disposal, flue gas desulfurization, wastewater treatment and equipment necessary for an efficient, available, and completely operable facility. The plant is designed using components suitable for a 30-year life, with provision for periodic maintenance and replacement of critical parts.

The steam cycle used for this supercritical case is based on a 3500 psig/1050°F/1050°F single reheat configuration. The turbine generator is a single machine comprised of tandem HP, IP, and LP turbines driving one 3,600 rpm hydrogen-cooled generator. The net plant output power, after plant auxiliary power requirements are deducted, is 518 MWe. The overall net plant efficiency is 39.9 percent. Overall performance for the entire plant is summarized in Table 8-1, which includes auxiliary power requirements.

Table 8-1
Supercritical PC Boiler Plant Performance Summary
100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	3,500
Throttle Temperature, °F	1,050
First Reheat Outlet Temperature, °F	1,050
Second Reheat Outlet Temperature, °F	1,050
POWER SUMMARY	
Steam Turbine Power	558,190
Generator Loss	-8,1900
Total, kWe (Generator terminals)	550,000
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	420
Limestone Handling & Reagent Preparation	180
Pulverizers	2,000
Ash Handling	1,800
Primary Air Fans	1,380
Forced draft Fans	1,090
Induced Draft Fans	3,960
SCR Auxiliaries	100
Seal Air Blowers	50
Precipitators	1,000
FGD Pumps and Agitators	4,900
Condensate Pumps	690
Boiler Feedwater Booster Pumps	3,600
High Pressure Boiler Feed Pumps	(Note 2)
Miscellaneous Balance of Plant (Note 3)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	4,700
Cooling Tower Fans	2,690
Transformer Loss	1,260
TOTAL AUXILIARIES, kWe	32,220
Net Power, kWe	517,780
Net Efficiency, % HHV	39.8%
Net Heat Rate, Btu/kWh (HHV)	8,564
CONDENSER COOLING DUTY, 10^6 Btu/h	2,070
CONSUMABLES	
As-Received Coal Feed, lb/h (Note 1)	356,177
Sorbent, lb/h	36,692

Note 1 - As-received coal heating value: 12,450 Btu/lb (HHV)
Note 2 - Boiler feed pumps are steam turbine driven.
Note 3 - Includes plant control systems, lighting, HVAC, etc.

8.1 HEAT AND MATERIAL BALANCE

The steam cycle used for this case is based on a 3500 psig/1050°F/1050°F single reheat configuration. The HP turbine uses steam at 3515 psia and 1050°F. The cold reheat flow is reheated to 1050°F before entering the IP turbine section.

The turbine generator is a single machine comprised of tandem HP, IP, and LP turbines driving one 3,600 rpm hydrogen-cooled generator. The feedwater train consists of seven closed feedwater heaters (four low pressure and three high pressure), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 518 MWe. The overall net plant efficiency is 39.8 percent.

The major features of this plant include the following:

- Boiler feed pumps are steam turbine driven.

Turbine configuration is a 3,600 rpm tandem compound, four-flow exhaust.

- Plant has seven stages of closed feedwater heaters plus a deaerator.

Figure 8-1 is a modified block flow diagram for the overall plant with individual streams identified. Table 8-2 follows the figure with detailed composition and state points for the numbered streams.

Figure 8-1
Supercritical PC Boiler Case – Block Flow Diagram

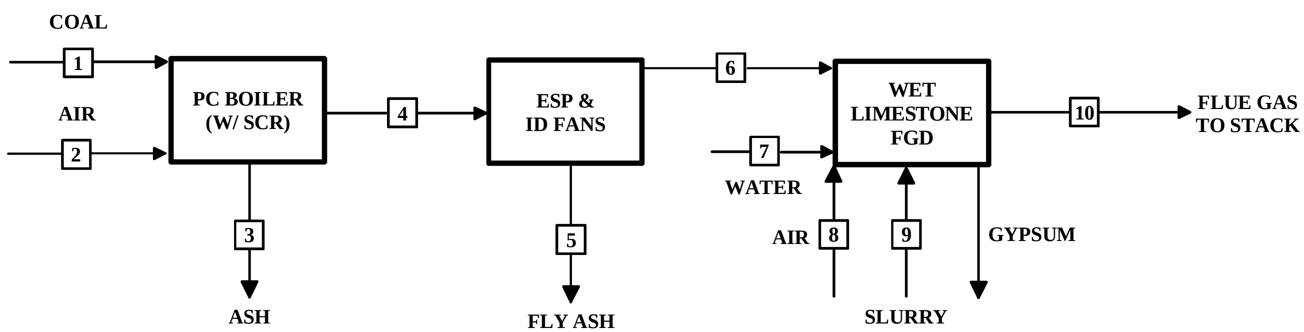


Table 8-2
Supercritical PC Boiler Stream Table

V	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0000	0.0094	0.0000	0.0090	0.0000	0.0090	0.0000	0.0094	0.0000	0.0084
CO_2	0.0000	0.0003	0.0000	0.1352	0.0000	0.1352	0.0000	0.0003	0.0000	0.1238
H_2O	0.0000	0.0108	0.0000	0.0708	0.0000	0.0708	1.0000	0.0104	1.0000	0.1350
O_2	0.0000	0.2076	0.0000	0.0404	0.0000	0.0404	0.0000	0.2077	0.0000	0.0414
SO_2	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0000	0.0000	0.0000	0.0001
N_2	0.0000	0.7719	0.0000	0.7424	0.0000	0.7424	0.0000	0.7722	0.0000	0.6913
Total	0.0000	1.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	0	145,801	0	151,812	0	151,812	13,448	926	4,756	168,272
V-L Flowrate (lb/hr)	0	4,206,273	0	4,526,070	0	4,526,070	242,073	26,722	85,615	4,865,518
Solids										
Coal (lb/hr)	356,177	0	0	0	0	0	0	0	0	0
Ash (lb/hr)	0	0	7,275	29,102	29,102	0	0	0	0	0
Limestone (lb/hr)	0	0	0	0	0	0	0	0	36,692	0
Temperature (°F)	59	59	300	281	280	343	59	59	100	131
Pressure (psia)	14.7	14.7	14.1	14.1	14.1	17.7	20.0	14.7	20.0	14.7

8.2 EMISSIONS PERFORMANCE

The 1990 CAAA imposed a two-phase capping of SO_2 emissions on a nationwide basis. For a new greenfield plant, the reduction of SO_2 emissions that would be required depends on the availability of SO_2 allowances to the utility, and on local site conditions. In many cases, Prevention of Significant Deterioration (PSD) Regulations will apply, requiring that Best Available Control Technology (BACT) be used. BACT is applied separately for each site, and results in different values for varying sites. In general, the emission limits set by BACT will be significantly lower than NSPS limits. The ranges specified in Table 8-3 will cover most cases. For this study, plant emissions are capped at values shown in Table 8-4.

Table 8-3
Emission Limits Set by BACT

SO_X	92 to 95 percent removal
NO_X	0.2 to 0.45 lb/10^6 Btu
Particulates	0.015 to 0.03 lb/10^6 Btu
Opacity	10 to 20 percent

Source: DOE/FE-0400 MARKET-BASED ADVANCED COAL POWER SYSTEMS FINAL REPORT MAY 1999

Table 8-4
Airborne Emissions
Subcritical PC

	lb/10^6 Btu	tons/year 80% capacity	lb/MWh
SO_2	0.232	3,607	1.872
NO_X	0.100	1,554	0.806
Particulates	0.024	372	0.193
CO_2	207	3,212,000	1,667

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 95 percent.

The minimization of NO_X production and subsequent emission is achieved by a combination of low- NO_X burners, overfire air staging, and selective catalytic reduction (SCR). The low- NO_X burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NO_X emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern electrostatic precipitator, which provides a particulate removal rate of 99.7 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (lb/MMBtu), since a similar fuel is used. However, total CO_2 emissions are lower than for a typical PC plant with this capacity due to the relatively high thermal efficiency.

8.3 WATER BALANCES

Figure 8-2 shows the water flows through the entire plant in gallons per minute. All the water is accounted for including the water lost in chemical reactions or gained in the combustion of coal. Table 8-5 shows an overall water balance for the entire plant and Table 8-6 shows the water loss by major function. The cooling water system is by far the largest water consumer accounting for nearly 84 percent of the water lost. Losses in the flue gas and FGD account for 16 percent of the total.

Table 8-5
Supercritical PC Boiler Overall Water Balance

Water In			**Water Out**		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
1	Moisture in coal	42.7	11	PC Boiler flue gas	817.8
2	Coal Combustion of H2 in Boiler	287.7	12	Water with gypsum	71.3
3	Combustion air for PC Boiler	56.8	17	Cooling tower evaporation	3,468
8	Oxidation air for FGD	0.3	18	Cooling tower blowdown	1,155
13	Raw Water	5,125			
		5,512			5,512

Table 8-6
Supercritical PC Boiler Water Loss by Function

FGD losses	Gpm	gal/MWh
Water with Gypsum	71.3	8.3
Total	71	8
Flue gas losses		
PC boiler Flue gas	817.8	94.8
Total	818	95
Cooling water losses		
Cooling tower blowdown	1,155	133.8
Cooling tower evaporation	3,468	401.9
Total	4,623	535.7
Grand Total	5,512	639

Figure 8-2
Supercritical PC Boiler Case – Block Flow Diagram – Water Flows in Gallons per Minute

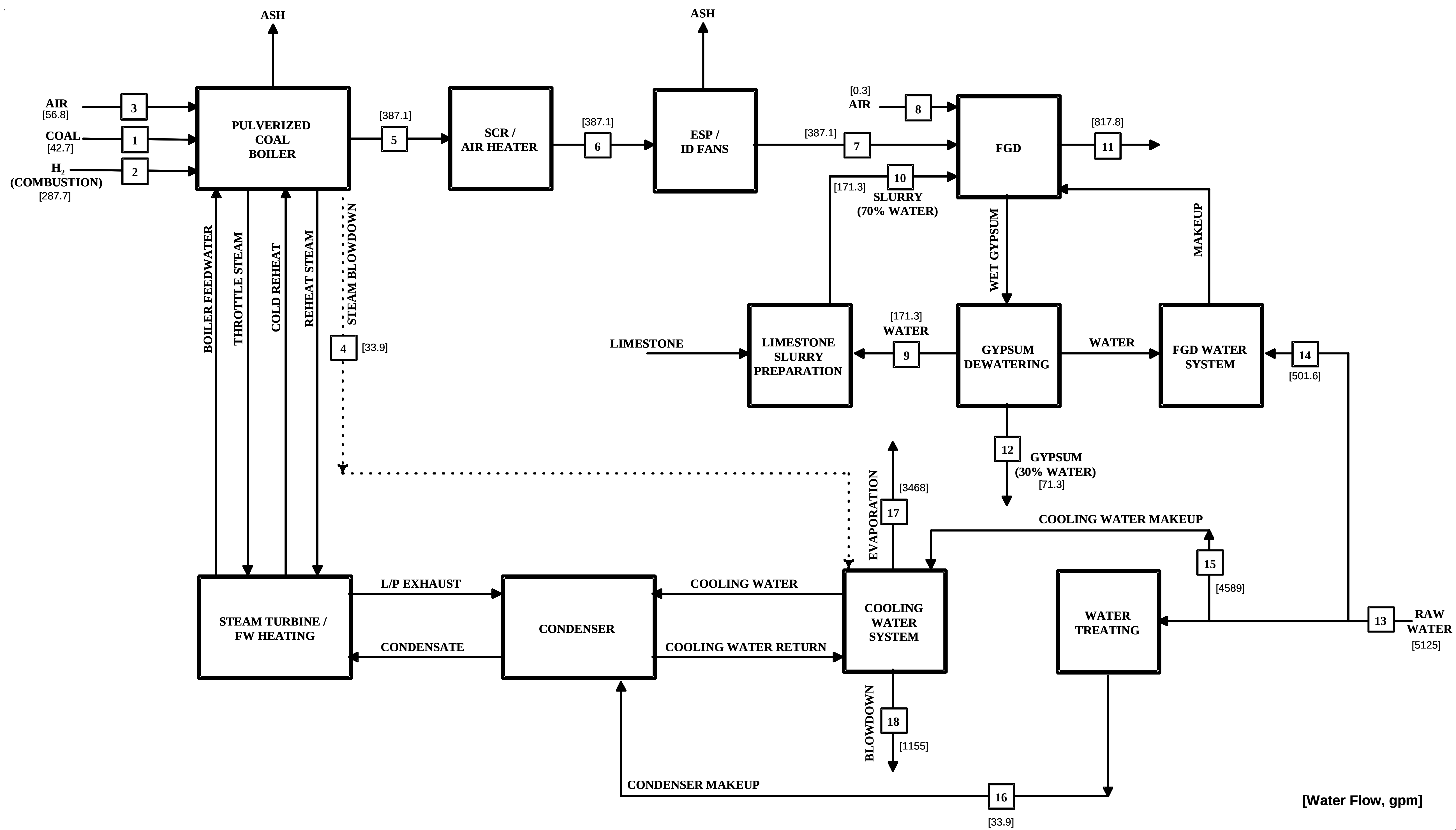


Table 8-7 shows the water balance around the FGD island. Over half of the water that ends up in the flue gas is evaporated from the FGD system.

Table 8-7
Supercritical PC Boiler Water Balance Around FGD Island

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
7	Moisture in flue gas	387.1	11	Moisture in flue gas	817.8
8	Oxidation air for FGD	0.3	12	Water in Gypsum	71.3
14	Makeup water	501.6			
		889			889

Table 8-8 shows the water balance around the cooling water system. Over 90 percent of the plant water losses occur here.

Table 8-8
Supercritical PC Boiler Water Balance Around Cooling Water System

Water In			Water Out		
No	Location	Flow (gpm)	No	Location	Flow (gpm)
4	Steam blowdown	33.9	17	Cooling tower evaporation	3,468
15	Cooling water Makeup	4,589	18	Cooling water blowdown	1,155
		4,623			4,623

8.4 WATER USAGE

The raw water usage as calculated in this study represents the total amount of water to be supplied from local water resources to provide for the needs of the plant. The amount differs from the total water losses, or the totals appearing in the Overall Water Balance. The difference is attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. Table 8-9 shows the raw water for the plant and the usage through branch streams required to supplement process losses and flue gas losses.

Table 8-9
Supercritical PC Boiler Raw Water Usage

Water In				Water Usage			
No	Location	Flow (gpm)	gal/ MWh	No	Location	Flow (gpm)	gal/ MWh
13	Raw Water	5,125	593.8	14	Water to FGD System	501.6	58.1
				15	Makeup to Cooling Tower	4,589	531.8
				16	Makeup to Condenser	33.9	3.9
		5,125	594			5,125	594

9. RESULTS

This study resulted in a series of tables and flow diagrams in each report section which document the water loss in specific areas of the study plants. These areas were divided into process losses, flue gas losses and cooling water losses. Also, the raw water usage was determined for each plant to provide an assessment of the makeup requirement and distribution into the plant. The results of the water utilization and loss study are summarized here in Table 9-1 and Table 9-2, shown in gallons per MWh (net) and MMBtu, respectively. The water balance reported with each technology section provides credible completeness for the accounting of water input, output, and uses. Water loss as a function of heat input (MMBtu) is more consistent among types of power plant than as a function of MWh. This is primarily due to inclusion of heat rate in the water loss calculation based on MWh.

An alternative presentation of the results is in the form of bar graphs as shown in Figure 9-1 to compare various types of gasifier and Figure 9-2 to compare technologies, both shown in gallons per MWh.

The results of the raw water usage are summarized in Table 9-3, shown in gallons per MWh. The results are also shown as a bar graph in Figure 9-3.

9.1 PROCESS LOSSES

Process losses are more pronounced with the IGCC plants due to the need to add water to the gasification reactions and promote shift within the gasifier to hydrogen and carbon dioxide. There are no process losses with the other plants other than the PC plants, which lose water with disposal of the FGD gypsum cake. The process losses in each of the systems are the smallest category of loss.

The Shell IGCC plant loses coal moisture initially as a water loss, due to the requirement to dry the coal prior to feeding to the gasifier. However, because of the dry feed, it uses less water in the gasification reactions, which are indicated as the water lost to shift reaction in the gasifier. Water lost to shift is the reduction of water content in the syngas resulting from the conversion of water present in the gasifier to hydrogen and carbon dioxide. The E-Gas case has less water lost to shift and less water converted to hydrogen and carbon dioxide, as reflected in the syngas composition. The E-Gas syngas contains nearly 20 percent more carbon monoxide and about 15 percent less hydrogen than either of the GE Energy cases.

Water lost with the slag is consistent for each of the IGCC cases, which reflects the dewatering of the slag and the water content in the residual cake. Minor amounts of water are lost in the COS hydrolysis bed, resulting from the hydrolysis of COS to H_2S and CO_2.

Sour Water Blowdown/Water Treatment Effluent can vary with the IGCC plant. The IGCC plant with the highest blowdown is the GE Energy Quench case due to the large sour water circulation rate around the gasifier quench tank. Rather than treat and discharge the entire process blowdown stream to the sewer, the stream is treated, 90 percent used as makeup for the cooling tower, with the remainder to the plant sewer.

9.2 FLUE GAS LOSSES

Flue gas losses are a reflection of the type of power plant and the methodology used for conditioning either the syngas or the flue gas. Each of the IGCC plants has syngas humidification for NOx mitigation, but the E-Gas and Shell cases also need additional steam injection to dilute the syngas. The GE Energy cases utilize only nitrogen injection to dilute the syngas. This can be seen in the variations of flue gas losses for the IGCC gas turbines. The NGCC does not utilize natural gas humidification before firing in the GT combustor, however the flue gas losses are indicative of the water produced from the air and fuel.

The PC power plants each have FGD. These wet processes result in significant water losses to the boiler flue gas.

9.3 COOLING WATER LOSSES

Eighty to ninety-nine percent of the power plant raw water usage is through a combination of cooling tower evaporation and blowdown. This water loss is based on a generic site and assumed cooling tower performance characteristics (see Section 1.3.3). Uniformly, cooling tower performance as a function of plant condenser duty (plus 100 MMBtu/h for auxiliary heat loads) was assumed for each power plant. Water loss differences are associated with plant condenser duty which can be traced back to plant efficiency and other uses of condensing steam such as methods of syngas humidification or syngas dilution. The E-Gas condenser duty is lower than the other IGCC cases due to that case utilizing more non-condensing steam for syngas dilution.

Table 9-1
Water Loss Summary, gallons per MWh

	E-Gas gal/MWh	Shell gal/MWh	GE R-C gal/MWh	GE Quench gal/MWh	NGCC gal/MWh	PC Sub gal/MWh	PC Supe gal/MWh
Process losses							
Coal drying moisture		3.3					
Water lost in gasification shift	11.1	6.0	16.7	18.2			
Ash quench blowdown	8.7	7.8	8.4	9.3			
Water with slag	3.0	3.7	3.3	3.7			
Water lost in COS hydrolysis	0.0	0.2	0.0	0.1			
Sour water blowdown	3.1	4.5	0.5	2.5			
Water with gypsum						9.3	8.3
Total	**26**	**25**	**29**	**34**	**0**	**9**	**8**
Flue gas losses							
GT flue gas	105.5	75.3	78.0	104.8	87.0		
Incinerator flue gas		1.5					
Boiler flue gas						107.0	94.8
Total	**106**	**77**	**78**	**105**	**87**	**107**	**95**
Cooling water losses							
Cooling tower blowdown	75.3	85.1	86.1	92.9	70.6	149.4	133.9
Cooling tower evaporation	225.9	255.5	258.5	278.9	212.0	448.5	401.9
Total	**301**	**341**	**345**	**372**	**283**	**598**	**536**
Grand Total	***433***	***443***	***452***	***510***	***370***	***714***	***639***

Table 9-2
Water Loss Summary, gallons per MMBtu

	E-Gas gal/MMBtu	Shell gal/MMBtu	GE R-C gal/MMBtu	GE Quench gal/MMBtu	NGCC gal/MMBtu	PC Sub gal/MMBtu	PC Supe gal/MMBtu
Process losses							
Coal drying moisture		0.4					
Water lost in gasification shift	1.3	0.7	1.9	1.9			
Ash quench blowdown	1.0	0.9	1.0	1.0			
Water with slag	0.3	0.4	0.4	0.4			
Water lost in COS hydrolysis	0.0	0.0	0.0	0.0			
Sour water blowdown	0.4	0.5	0.1	0.3			
Water with gypsum						1.0	1.0
Total	**3.0**	**3.0**	**3.3**	**3.5**	**0**	**1.0**	**1.0**
Flue gas losses							
GT flue gas	12.1	8.9	9.0	10.9	12.7		
Incinerator flue gas		0.2					
Boiler flue gas						11.1	11.1
Total	**12.1**	**9.0**	**9.0**	**10.9**	**12.7**	**11.1**	**11.1**
Cooling water losses							
Cooling tower blowdown	8.6	10.0	9.9	9.7	10.3	15.5	15.6
Cooling tower evaporation	25.9	30.1	29.8	29.0	31.0	46.5	46.9
Total	**34.6**	**40.1**	**39.8**	**38.6**	**41.3**	**62.0**	**62.6**
Grand Total	***50***	***52***	***52***	***53***	***54***	***74***	***75***

Figure 9-1
IGCC Water Loss Summary for Various Gasifier Types, gallons per MWh

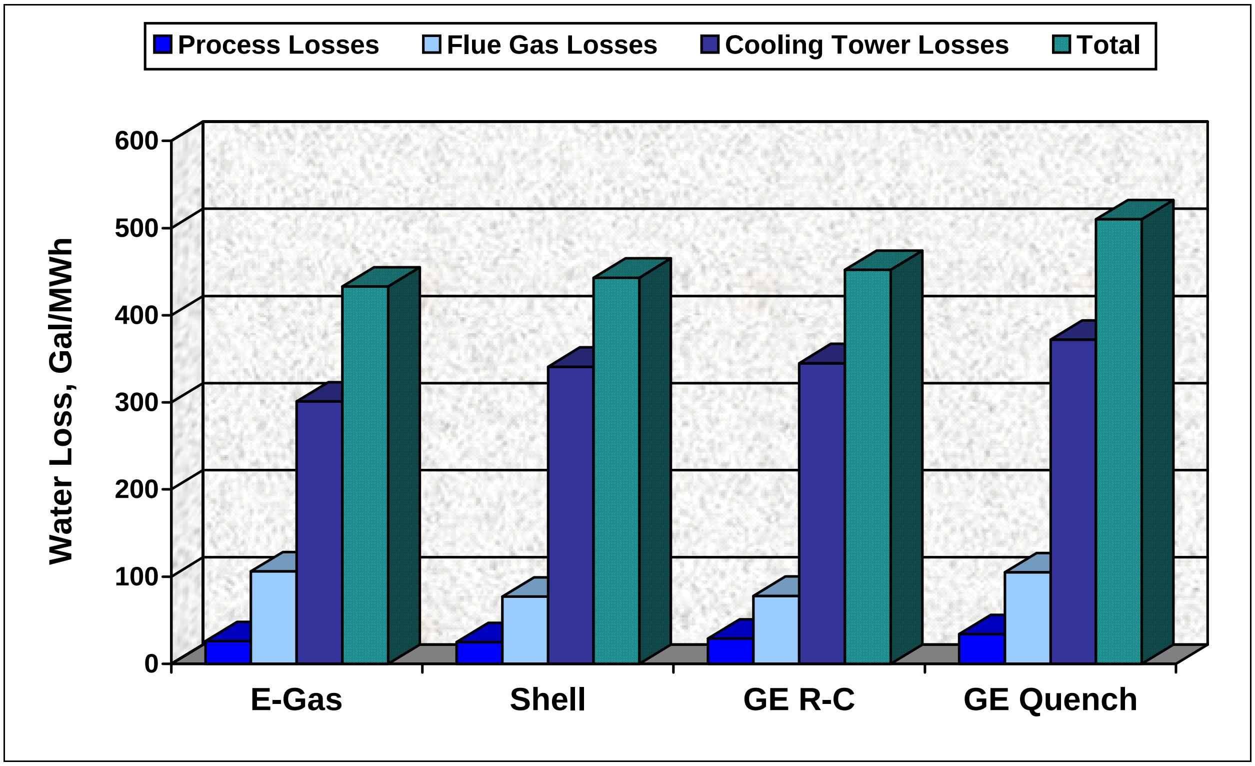
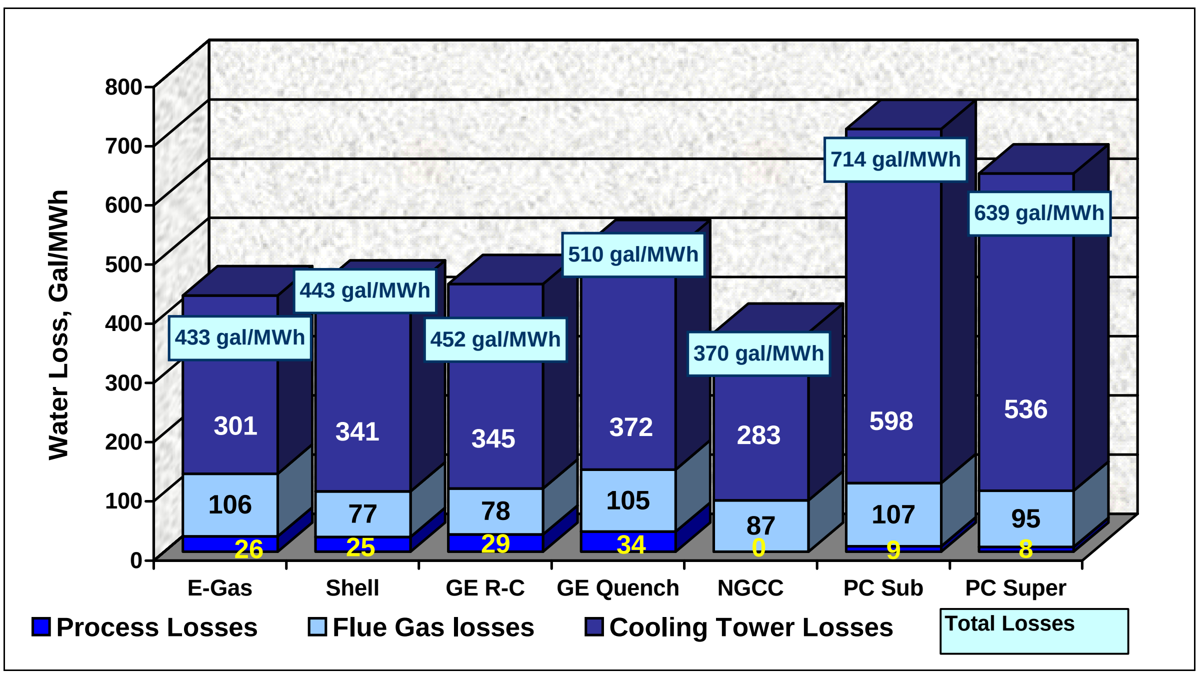


Figure 9-2
Comparison of Water Loss for Various Fossil Plants, gallons per MWh



9.4 RAW WATER USAGE

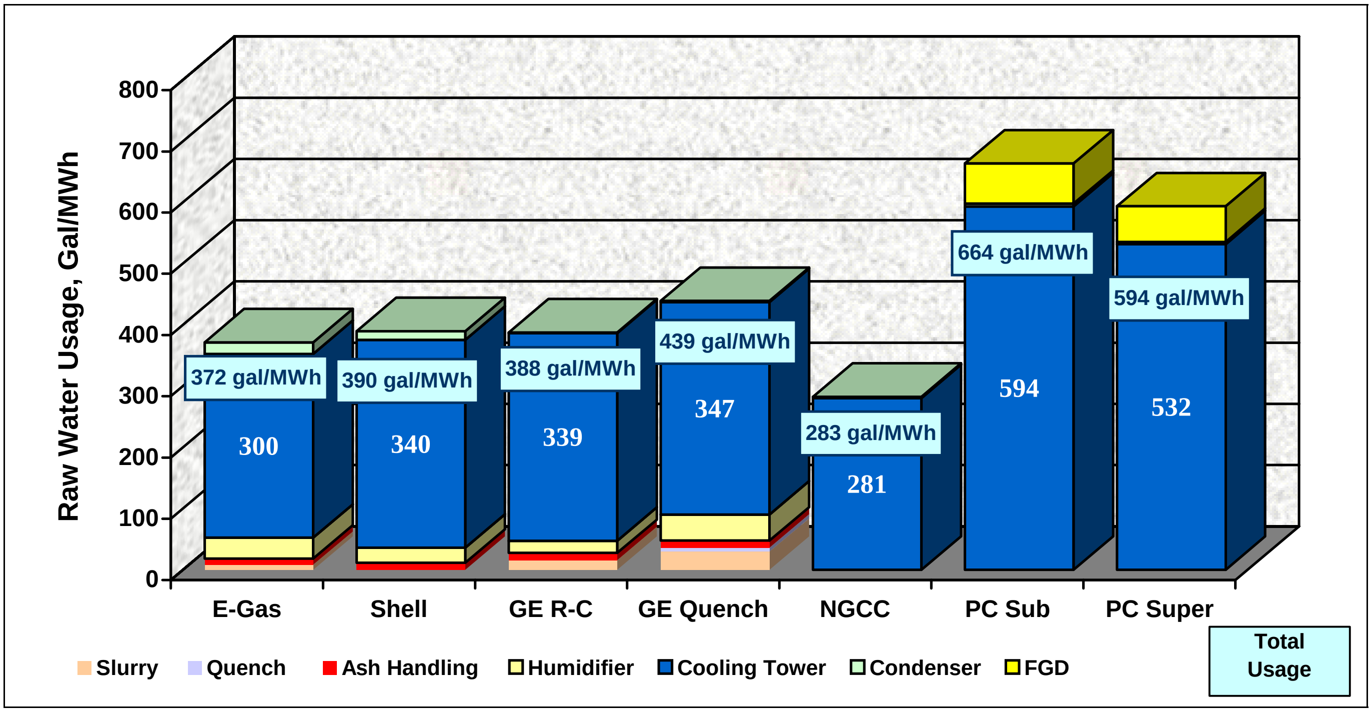
The raw water usages as calculated in this study represent the total amounts of water to be supplied from local water resources to provide for the needs of the plants. The amounts differ from the total water losses, or the totals appearing in the Overall Water Balances. The differences are attributable to water contributed to the balance via humid air intake to the process, water content of the fuel, and water produced in gasification/combustion. For example, the raw water usage to the cooling tower is calculated as the raw water makeup delivered directly to the cooling tower while the cooling tower loss calculation includes water recycled from other sources. The raw water usage for each power plant can be the determining factor for siting and permitting, as it identifies the impact of the plant on local water availability. The results show that the volume of raw water for each plant is dominated by the makeup requirement for the cooling tower. The raw water feed stream is also divided into branch streams required to supplement process losses and flue gas losses.

The results of the raw water usage calculations are summarized in Table 9-3, shown in gallons per MWh. The results are also shown as a bar graph in Figure 9-3. The usage is a better measure of the water requirement that would be needed for input to each plant type.

Table 9-3
Raw Water Usage Summary, gallons per MWh

	E-Gas	Shell	GE R-C	GE Quench	NGCC	PC Sub	PC Super
Raw Water Usage	gal/ MWh	gal/ MWh	gal/ MWh	gal/ MWh	gal/ MWh	gal/ MWh	gal/ MWh
Makeup to Slurry System	8.2		15.9	29.6			
Makeup to Quench				6.4			
Makeup to Ash handling	10.0	11.5	11.6	11.9			
Makeup to Humidifier	34.4	24.7	20.0	42.4			
Makeup to Cooling Tower	300.1	339.6	339.1	347.2	280.7	593.6	531.8
Makeup to Condenser	18.9	14.0	1.0	1.7	1.9	4.4	3.9
Water to FGD System						65.8	58.1
	371.5	389.8	387.6	439.2	282.6	663.8	593.8

Figure 9-3
Comparison of Raw Water Usage for Various Fossil Plants, gallons per MWh



9.5 RECOMMENDATIONS

This study is the initial phase of an effort to thoroughly document the use of water in power plants, particularly in IGCC applications. The plant configurations used here are based on current commercial offerings and on rigorous systems analysis results. The sites are generic middle USA and water for process and cooling makeup is readily available. There were no economic analyses performed.

The plant designs from this study can be used as a baseline for conducting additional systems analysis. Future analysis could be based upon such design changes as location, water use limitations, and plant efficiency. The sensitivity of water loss to changes in process design could also be determined. Following is a list of possible comparisons which could be used to alter the baseline power plant results.

- Arid Region power plant design
- Use of wet-dry cooling or dry cooling
- IGCC in hot, humid Texas climate
- IGCC in hot, dry west Texas or New Mexico climate
- IGCC in cold, dry, high elevation Wyoming
- IGCC with high moisture low rank coals
- IGCC with higher or lower solids loaded bituminous coal slurry feed
- Transport Reactor gasifier
- Different technology application such as H-turbine, or warm-gas cleaning that changes the efficiency and heat rejection, i.e., water needs.
- A power plant with once-through cooling of the steam cycle portion of the plant.

This report should provide some basis for reviewing the design assumptions, technology capabilities, system performance, etc and identify areas where new technology approaches or gasifier designs could lead to substantially lower water requirements. In turn, this can be a tool for planning R&D and gaining acceptance of out-of-the-box proposals for R&D projects. Examples might be:

- Recycle captured CO_2 as the transport media for coal into the gasifier eliminating the slurry requirement. Since the slurries use recycled water, is this a real reduction of water loss, or merely a displacement within the total system?

- Higher temperature, non-diluted fuel feed to gas turbine leading to higher GT exit temperature and greater heat recovery in steam cycle – thus different water requirements for cooling. For R&D planning, this identifies high temperature turbine, cleaner syngas for feed to GT, higher temperature and efficiency HRSG, etc.

- Is wet-dry cooling, dry cooling, or once-through cooling more or less attractive from water loss perspective for one technology versus the others?

- This study has evaluated the water usage and loss for each technology at standard design conditions. It would be appropriate to assess the variations in water requirements with external climate and plant utilization schedules to determine both the maximum water requirements and the average resource withdrawal rates that might be needed to support each of these plant types.

It is recommended that this study and report be used to provide baseline cases and methodology for assessing water usage and loss in various power plant technology conceptual designs. By providing the user of this report with a thorough determination of water input, output, and uses, both internal to the plant and with external requirements for makeup and discharge, the study provides the framework needed to assess water loss issues related to technology selection and design.